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Ratesetting

TO PARTIES OF RECORD IN APPLICATION 11-11-002

This is the proposed decision of Administrative Law Judge Douglas Long. Until and unless the Commission hears the item and votes to approve it, the proposed decision has no legal effect. This item may be heard, at the earliest, at the Commission's May 15, 2014 Business Meeting. To confirm when the item will be heard, please see the Business Meeting agenda, which is posted on the Commission's website 10 days before each Business Meeting.

Parties of record may file comments on the proposed decision as provided in Rule 14.3 of the Commission's Rules of Practice and Procedure.

The Commission may hold a Ratesetting Deliberative Meeting to consider this item in closed session in advance of the Business Meeting at which the item will be heard. In such event, notice of the Ratesetting Deliberative Meeting will appear in the Daily Calendar, which is posted on the Commission's website. If a Ratesetting Deliberative Meeting is scheduled, ex parte communications are prohibited pursuant to Rule 8.3(c)(4)(B).

/s/ MARYAM EBKE for
Timothy J. Sullivan,
Chief Administrative Law Judge (Acting)

TJS:sk6

Attachment

Decision **PROPOSED DECISION OF ALJ LONG (Mailed 4/15/14)**

BEFORE THE PUBLIC UTILITIES COMMISSION OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U902G) and Southern California Gas Company (U904G) for Authority To Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	Application 11-11-002 (Filed November 1, 2011)

DECISION IMPLEMENTING A SAFETY ENHANCEMENT PLAN AND APPROVAL PROCESS FOR SAN DIEGO GAS & ELECTRIC COMPANY AND SOUTHERN CALIFORNIA GAS COMPANY; DENYING THE PROPOSED COST ALLOCATION FOR SAFETY ENHANCEMENT COSTS; AND ADOPTING A RATEMAKING SETTLEMENT

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1. Summary

1.1. Executive Summary

This decision addresses three issues: first it adopts a plan for pipeline Safety Enhancement, although it also finds that the proposed budget is too rudimentary to preapprove. However, we want the applicants to implement Safety Enhancement now. Therefore, we adopt the concepts embodied in the Decision Tree and authorize a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to record the costs incurred, subject to refund, after a reasonableness review. SDG&E and SoCalGas must file one or more subsequent applications with detailed management, engineering, and accounting records to recover reasonable costs in rates. Second, this decision, in compliance with our settlement rules, adopts a reasonable all-party settlement for SDG&E and SoCalGas' Triennial Cost Allocation proceeding, which is a cost allocation, marginal cost, and rate design proceeding commonly referred to as a "phase 2" general rate case. Third, this decision rejects a specific cost allocation modification proposed to allocate the costs of Safety Enhancement based on human exposure to risk rather than the cost of providing service to all customer classes. The following decision discusses these issues in the above order.

1.2. Decision Overview

This decision finds that San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) have presented a reasonable, albeit conceptual plan to enhance the safety of their natural gas pipeline system (Safety Enhancement). The forecast costs include capital expenditures of $229 million for SDG&E and $1.2 billion for SoCalGas, and annual operating costs of $7 million for SDG&E and $255 million for SoCalGas. In this decision, we adopt a process to recover the Costs of Safety Enhancement by creating new balancing accounts which allow the companies to begin work and recover their costs subject to refund after the Commission reviews SDG&E and SoCalGas' new applications with project specific management, engineering, and cost records that demonstrate the reasonableness of cost recovery of the detailed implementation plan as executed by the Companies.

SDG&E and SoCalGas failed to maintain construction records or data for portions of the pipelines that would demonstrate the proper testing of these pipelines to the standards that the Commission has determined to be necessary in Decision 11-06-017. Although many of these pipelines operated for many years without failure, we can no longer assume or presume them to be safe. Because these pipelines can no longer be presumed to be safe, they can no longer be presumed to be used and useful to provide service to customers unless tested or replaced. Ratepayers should not pay twice to have a properly installed system in place, therefore, the cost of such tests for facilities installed after January 1, 1956, must be absorbed by the shareholders of SDG&E and SoCalGas in situations where the company has failed to maintain records of strength testing required at the time of installation of the pipeline.

Whenever SDG&E or SoCalGas cannot produce a record of a pressure test required at the time of installation of the pipeline and whenever the existing systems cannot be properly tested and proven to be safe, or for other reasons it is determined they should be replaced, then we will treat the remaining book value of these existing systems as abandoned plant and allocate those costs to the shareholders of SDG&E and SoCalGas. The ratepayers must however pay for the cost of the new system; the ratepayers clearly benefit by receiving a brand-new system, which will be safe, and which will safely serve them for decades.

The record shows that SDG&E and SoCalGas have over 385 miles of pipeline segments which require pressure testing or replacement because documentation does not sufficiently meet modern requirements or does not demonstrate that at the time of construction, the pipeline segments were properly strength tested in compliance with industry best practices or mandatory regulations in place at the time of installation to support their ongoing safety operations.[1] The record also shows that SoCalGas has 23 miles of pipeline which has not been pressure tested through a static strength test, but the company has lowered this pipeline's pressure to a level at which, the company states, the pre-reduction pressure provides for a "pressure-carrying" equivalent of 125% of Maximum Allowable Operating Pressure.

We cannot estimate the true magnitude of either the testing or replacement costs or the impact on either ratepayers or shareholders at this time. Although

[1] *See* the Decision Tree: Where the pipeline is operated in a class 3 or 4 location or high Consequence Area and not documented for pressure testing to 1.25 times Maximum Allowable Operating Pressure.

ratepayers will bear the costs of the new and safer pipeline systems as installed, we cannot reasonably forecast and preapprove Safety Enhancement costs at this time because SDG&E and SoCalGas do not have reliable detailed cost estimates, nor can we adequately estimate the cost for testing pipelines or the remaining book value of abandoned pipelines that will be absorbed by the shareholders. This must be resolved later.

We cannot quantify the change in the degree or level of safety achieved by these anticipated projects as a part of Safety Enhancement. There is simply no metric for potential lives to be saved, avoidance of personal injury, avoidance of property loss or damages, or disruptions to the economy that would result if the unmodified pipeline system remained in service as is. What we do know is that the system will be built to the best current practices, that there will be proper permanent documentation of the construction, and that the company will continue to operate the systems in a safe and reliable fashion with the capacity to do inspections and tests that may not be possible to perform on the current system.

This proceeding is closed.

2. Application Background

San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) (collectively Applicants or SDG&E and SoCalGas) filed the required Triennial Cost Allocation Proceeding (Cost Allocation). In Rulemaking (R.) 11-02-019, the assigned Commissioner ruled that this Cost Allocation proceeding for both Applicants would be the most logical proceeding for the SDG&E and SoCalGas reasonableness and ratemaking review of the companies' Safety Enhancement Plans (Safety Enhancement) because this proceeding deals with all cost allocation and rate design. Therefore, Safety Enhancement was

reassigned here to take advantage of the evidentiary record and policy decisions emerging on rate design and cost allocation. (*See* Ruling dated December 21, 2011.)

The Commission opened R.11-02-019 to review and establish a new model of natural gas pipeline safety regulation for California. Decision (D.) 11-06-017 ordered all California natural gas transmission pipeline operators to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans (Implementation Plans) to either pressure test or replace all segments of natural gas pipelines which were not pressure tested or lack sufficient details related to performance of any such test. The Commission required that the Implementation Plans provide for testing or replacing all such pipelines as soon as practicable, and that at the completion of the implementation period, all California natural gas transmission pipeline segments would be (1) pressure tested, (2) have traceable, verifiable, and complete records readily available, and (3) where warranted, be capable of accommodating in-line inspection devices. In addition, the Commission required the operators to implement interim safety enhancement measures, including increased patrols and leak surveys, pressure reductions, prioritization of pressure testing for critical pipelines that must run at or near Maximum Allowable Operating Pressure values which result in hoop stress levels at or above 30% Specified Minimum Yield Stress, and other such measures that will enhance public safety during the implementation period.

On December 2, 2011, SDG&E and SoCalGas filed their Safety Enhancement plans[2] in the rulemaking. Safety Enhancement, if adopted as filed, provides for hundreds of millions of dollars in annual investment over more than a decade beginning with capital forecasts for Phase 1A of $1.2 billion for SoCalGas and $229 million for SDG&E and operating and maintenance forecasts for Phase 1A of $255 million for SoCalGas and $7 million for SDG&E. SDG&E and SoCalGas also seek to include a Phase 1B[3] of projects that would be more economical and efficient if constructed concurrently with related Phase 1A projects. In an effort to decrease these costs, Safety Enhancement also includes proposals to non-destructively examine, in lieu of testing, pipeline segments of 1,000 feet or less.

In addition to the testing or replacing pipeline, Safety Enhancement includes modifications of 541 valves, and the addition of 20 valves, to provide for automated shut-off capability in order to isolate, limit the flow of gas to no more than 30 minutes, and thereby facilitate timely access of "first responders" into the area surrounding a substantial section of ruptured pipe. Safety Enhancement also includes: 1) improvements to communications and data gathering to ascertain pipeline conditions; 2) installing backflow valves to prevent gas from flowing into sections intended to be isolated from other connected lines;

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[2] The term "Pipeline Safety Enhancement Plan" is the personalized name used by both Applicants in their compliance filings for the "Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans" ordered in D.11-06-017 and we will use Applicants' name, contracted to Safety Enhancement, hereafter, unless specifically citing to the filing original requirement.

[3] That is, Phase 1B are proposed tasks which SDG&E and SoCalGas believe would be more economical and efficient if done concurrently with Phase 1A but do not meet Phase 1 criteria on their own.

3) expand the coverage of SDG&E and SoCalGas' private radio networks to serve as back-up to other available means of communications with the newly installed valves to improve system reliability; 4) installing remote leak detection equipment; and 5) increasing physical patrols and leak survey activities.

Pursuant to Pub. Util. Code § 451, each public utility in California must "furnish and maintain such adequate, efficient, just and reasonable service, instrumentalities, equipment, and facilities, . . . as are necessary to promote the safety, health, comfort, and convenience of its patrons, employees, and the public." Ensuring that the management of investor-owned gas utility systems fully performs its duty of safe operations is a top priority of this Commission, and the California Legislature has recently confirmed this critical function of the Commission.[4]

As set forth in D.11-06-017[5], the Commission found that 1970 federal and 1961 California regulations for gas pipeline safety established requirements for the pressure testing natural gas transmission pipeline facilities; however, these applied only to new pipeline facilities and exempted all pre-existing in-service

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[4] Pub. Util. Code § 963(b)(3) finds that: It is the policy of the state that the commission and each gas corporation place safety of the public and gas corporation employees as the top priority. The commission shall take all reasonable and appropriate actions necessary to carry out the safety priority policy of this paragraph consistent with the principle of just and reasonable cost-based rates.

[5] The Commission's General Order 112, which became effective on July 1, 1961, mandated pressure test requirements for new transmission pipelines (operating at 20% or more of Specified Minimum Yield Strength installed in California after the effective date. Similar federal regulations followed in 1970, but exempted pipeline installed prior to that time from the pressure test requirement. Such pipeline is often referred to as "grandfathered" pipeline, because pursuant to 49 CFR §192. 619(c), pressure testing was not mandated.

pipeline from the pressure test requirement. Accordingly, all pipelines installed after those dates are expected to be pressure tested, with the result that some of the oldest in-service natural gas pipeline has not been subjected to post-construction pressure testing to determine its Maximum Allowable Operating Pressure. Instead, the Maximum Allowable Operating Pressure for these untested pipeline segments is set by the highest recorded operating pressure on that segment during a defined time period.[6] Consequently, the operational records for the exempted pipeline segments are critical to determining their Maximum Allowable Operating Pressure.

After review of the detailed record in R.11-02-019 and before the National Transportation Safety Board regarding the records and vintage pipeline, the Commission concluded that the historic exemption and the utilities' record-keeping deficiencies had resulted in circumstances inconsistent with the safety, health, comfort, and convenience of utility patrons, employees, and the public. The Commission ordered all natural gas transmission pipelines in service in California to be brought into compliance with modern standards for safety, and that all California natural system operators file and serve a proposed Implementation Plan to comply with the requirement that all in-service natural gas transmission pipelines in California have been pressure tested in accord with 49 CFR Part 192 §§ 192.505 and 192.507 excluding reliance solely on § 192.619(c).

The Commission required that the Implementation Plans include interim safety enhancement measures, and that the analytical focus be a list of all transmission pipeline segments that have not been previously pressure tested,

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[6] 49CFR §192.619(c).

with pipeline that must run at or near operating pressures that result in hoop stress levels at or above 30% of Specified Minimum Yield Strength to receive prioritized designations for replacement or pressure testing. The Commission required the operators to also give high priority to pipeline segments located in Class 3 and Class 4 locations and High Consequence Area pipelines in Class 1 and 2 locations, with pipeline segments in other locations given lower priority for pressure testing.[7] The operators were required to set forth the criteria on which pipeline segments were identified for replacement instead of pressure testing.

The Commission also required each operator to include in the Implementation Plan a priority-ranked schedule for pressure testing all pipeline not previously so tested, and to provide for pressure reductions where necessary. The Implementation Plan also must address retrofitting pipeline to allow for in-line inspection tools and the installation of, where appropriate, automated or remote-controlled shut-off valves in order to limit the flow of gas from a large breach or rupture to a pipeline segment located in a Class 3 and Class 4 locations and HCAs in Class 1 and 2 locations. The Commission, when adopting PG&E's safety enhancement plan in D.12-12-030, has already clearly articulated its

[7] The Pipeline and Hazardous Materials Safety Administration regulations define the four class locations by number of human-occupied buildings located within 220 yards of the pipeline: Class 1, 10 or fewer buildings; Class 2, 10 to 45 buildings; Class 3, 46 or more buildings, or with a place of public assembly; and, Class 4, where buildings with four or more stories are prevalent. (49 CFR § 192.5.)

philosophy and policy that natural gas pipelines must be made to be safe and reliable. We adhere here to that same commitment.[8]

While emphasizing the importance and need to make these safety improvements in California's natural gas transmission systems, the Commission also stressed that it will closely scrutinize the costs to be imposed on ratepayers. In D.11-06-017, the Commission required that the Implementation Plans explicitly analyze cost and demonstrate that the proposed expenditures obtain the greatest safety value for ratepayers. The Commission stated its commitment to ensuring that California's working families and businesses pay only for necessary safety improvements, and the Commission encouraged customers to participate in the process for reviewing the Implementation Plans.

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[8] Among all public utility facilities, natural gas transmission and distribution pipelines present the greatest public safety challenges. Unlike more common public utility facilities, gas pipelines carry flammable gas under pressure - in transmission lines, often at high pressure - and these pipelines are typically located in public right-of-ways, at times in densely populated areas. The dimensions of the threat to public safety from natural gas pipeline systems, including the pace at which death and life-altering injuries can occur, are far more extreme than other public utility systems. This unique feature requires that natural gas system operators and this Commission assume a different perspective when considering natural gas system operations. This perspective must include a planning horizon commensurate with that of the pipelines; that is, in perpetuity, as well as an immediate awareness of the extreme public safety consequences of neglecting safe system construction and operation.

In the context of an unending obligation to ensure safety, we must also realize that in practical terms safety is exacting, detailed, and repetitive. It is also expensive, so ensuring that high value safety improvements are prioritized and obtaining efficiencies wherever possible is also essential. And, in the end, if the goal of safe operations is met, the reward is that absolutely nothing bad happens. In short, safety is difficult, expensive and seemingly without reward. (D.12-12-030 at 43.)

3. Burden and Standard of Proof, and Record

3.1. Overview

Pursuant to Pub. Util. Code § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified." (§ 454.) The Commission requires that the public utility demonstrate with admissible evidence that the costs it seeks to include in revenue requirement are reasonable and prudent. The Commission is charged with the responsibility of ensuring that all rates demanded or received by a public utility are just and reasonable.

SDG&E and SoCalGas must meet the burden of proving that they are entitled to the relief sought in this proceeding, and SDG&E and SoCalGas have the burden of affirmatively establishing the reasonableness of all aspects of the application.[9]

With the burden of proof placed on SDG&E and SoCalGas, the Commission has held that the standard of proof SDG&E and SoCalGas must meet is that of a preponderance of evidence. Preponderance of the evidence usually is defined "in terms of probability of truth, e.g., 'such evidence as, when weighed with that opposed to it, has more convincing force and the greater

[9] See generally Application of Southern California Edison Company for Authority to, Among Other Things, Increase Its Authorized Revenues For Electric Service in 2009, And to Reflect That Increase In Rates (D.09-03-025, *mimeo*. at 8) (March 12, 2009) and Decisions cited therein.

probability of truth'"[10] In short; SDG&E and SoCalGas must present more evidence that supports the requested result than would support an alternative outcome.

We have analyzed the record in this proceeding within these parameters. These are the same parameter used for Pacific Gas & Electric Company (PG&E). (D.12-12-030 at 41.)

3.2. Application of Standard

It is thus quite clear that SDG&E and SoCalGas bear the burden of proof for the reasonableness of its past practices in building, maintaining, and operating the pipeline systems and for its ratesetting proposals in this proceeding. Parties have debated what standard to apply: clear and convincing or preponderance, a lower standard. The Commission's standard for reasonableness issues is the preponderance standard, and we find that at even the lower standard of preponderance of evidence, SDG&E and SoCalGas failed to have adequate and reliable records for significant segments of their system and must therefore bear some of the consequences that result from those inadequate records. We further find that SDG&E and SoCalGas's showing was inadequate in detail and thoroughness to approve Safety Enhancement as proposed thus failing the usual preponderance test. This has been one of the main challenges in this proceeding. Therefore, as discussed below, we will require further showing before approving any final cost recovery from the balancing accounts.

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[10] In the Matter of the Application of San Diego Gas & Electric Company for a Certificate of Public Convenience and Necessity for the Sunrise Powerlink Transmission Project, D.08-12-058, *citing* Witkin, Calif. Evidence, 4th Edition, Vol. 1, 184.

3.3. Record

The record for this proceeding consists of the documents filed and served and the testimony and exhibits admitted during the evidentiary hearings. This record is the sole basis for this decision.

4. SDG&E & SoCalGas' Safety Enhancement

4.1. Decision Tree

SDG&E and SoCalGas produced two exhibits, the first of which is a "Decision Tree" included here as Attachment I,[11] and a more complicated table that reconciled all the natural gas pipeline system into various classifications or risk factors, age, documentation, etc., referred to as a "Reconciliation" included here as Attachment II.[12]

The Decision Tree results in a first cut allocation of SDG&E and SoCalGas's pipelines into the proposed phases 1A, 1B, and Phase 2. It is the heart of SDG&E and SoCalGas's Safety Enhancement process.

The Decision Tree and Reconciliation are works in progress, showing the first steps taken by SDG&E and SoCalGas to define the scope of work for Safety Enhancement. SDG&E and SoCalGas began by categorizing the existing system's condition and risk. Phase 1A is the first most critical grouping of pipeline facilities which need to be addressed. SDG&E and SoCalGas also proposed a Phase 1B comprised of facilities adjacent to Phase 1A, but otherwise with a lower priority, that for efficiency or sound engineering reasons should be included with the higher priority facilities.

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[11] Ex. SCG-33-R.

[12] Ex. SCG-34-R.

In its January 17, 2012 Technical Report on SDG&E and SoCalGas's Pipeline Safety Enhancement Plan, the CPUC's Safety and Enforcement Division (Safety Div.), then Consumer Protection and Safety Division, discussed its review of SDG&E and SoCalGas's Safety Enhancement process, including its Decision Tree (in an earlier form to the Decision Tree in Attachment I). The Safety Div. report stated: "The use of a documented pressure test of (125% of Maximum Allowable Operating Pressure) at the start of the … decision tree process, is a conservative, first cut, approach…" and that as shown by research, "…it can provide some level of assurance as to the stability of the longitudinal seams on a pipeline." The Safety Div. report went on to find that: "Overall, the … decision tree process for prioritization in Phase 1A, and the sub-prioritization process included therein, appears to result in reasonably prioritized segments."

In regard to automated valves, the Safety Div. report found that SDG&E and SoCalGas "…have used a sound approach towards determining where automated valves should be installed in order to reduce the consequences of a major breach. This approach appropriately considers pipeline diameter, the operating stress on the line, and geological threats as part of the determination process." Essentially, the Safety Div. found that the companies' proposal to use remote controlled valves to isolate (generally purged of gas) an 8-mile segment of pipeline of any diameter, within 15 minutes of the last valve necessary for isolation being closed, as reasonable. However, Safety Div. did recommend that fewer automated valves, instead of remote controlled valves included in Safety Enhancement, would provide similar protection, albeit with a slight increase in risk of gas loss due to false closures.

4.1.1. Decisions Made Under the Decision Tree

The Decision Tree starts with 3,885 total miles: 245 for SDG&E, and 3,630 for SoCalGas. By the end of the process it has allocated those miles into a variety of sub-categories: for immediate replacement; or testing and possible replacement; inspection and then either replacement or left in service; or those for which there is no further action. In fact the largest grouping of pipeline of 3,305 miles, falls into Boxes 8 and 9, no further action category, and only 385 miles fall into the most complex categories where they are Class 3 or 4 Locations, or High Consequence Areas, and not documented as ever having been strength tested to a level of 125% of Maximum Allowable Operating Pressure.

Some parties argue that Phase 1B should be considered later after the most critical portions of the system are resolved in Phase 1A. If we have learned one institutional lesson it would be that we need to look at safety generally, and Safety Enhancement in particular, as an integrated and ongoing commitment and that it is not a couple of quick fixes. Therefore, we approve the Decision Tree as it embodies the decision making processes for SDG&E and SoCalGas.

We should also clarify that while the record is complex and parties argue the merits of Safety Enhancement we intend to adhere to pre- and post-January 1, 1956 date as the pivotal date for the testing and retention of records for steel pipeline to operate at a hoop stress of 20 percent or more of Specified Minimum Yield Strength. Although SDG&E and SoCalGas argue they should only be accountable for testing after July 1960 when our rules were updated, it is clear to us that industry standards in fact changed as of January 1, 1956. We believe that as prudent managers using the best practices of the era SDG&E and SoCalGas should have not ignored those changes and await

an update to the Commission's rules before following best practices. This is also consistent with our adopted position for PG&E in D. 12-12-030. We adopt it here because it reflects industry best practices and not solely to be consistent with our decisions for PG&E.

4.2. Positions of the Parties

4.2.1. Office of Ratepayer Advocates - Summary

The Office of Ratepayer Advocates[13] (ORA) argues that for the years 2012 through 2015, SDG&E and SoCalGas ask the Commission to order ratepayer funding of a total of approximately $1.7 billion in capital expenditures and Operations and Maintenance expenses for direct costs only; excluding carrying costs such as taxes, depreciation, rate of return or other costs necessary to support the investment. Even using this incomplete estimate, ORA is gravely concerned that this would be a 10% rate hike. (Opening Brief at 1.) Further, ORA notes the Commission has stated its "… primary efforts have been focused on ensuring that California's natural gas transmission system operators are properly calculating the Maximum Allowable Operating Pressure for each segment of the natural gas pipeline transmission system." (Citing to D.12-04-021, at 1.) ORA points out the Commission has ordered utilities to prepare Natural Gas Transmission Pipeline Comprehensive Pressure Testing Implementation Plans. According to , SDG&E and SoCalGas,the companies need $12 billion worth of revenue requirements to assure the Commission that it is properly calculating the Maximum Allowable Operating Pressure for its gas transmission

[13] Like Safety Div., ORA had a name-change during this proceeding. The exhibits in the record introduced by ORA are labeled with the old acronym "DRA" and therefore those citations will use "DRA" whereas we will use ORA for the entity in this decision.

system. In DRA's opinion "if that is indeed true, then something is very wrong here. Either the Sempra utilities' gas transmission system is in a terrible state of disrepair, or the utilities are using the opportunity to pad shareholder returns by proposing capital improvement projects that are well beyond the primary directive of the Commission. Clearly, Sempra's ratepayers should not be forced to pay for the remedial or excessive improvements Sempra proposes." (DRA Opening Brief at 2.)

ORA proposes that for the years 2012 through 2015:

- the Commission authorize ratepayer funding of no more than $69.75 million for the combined utilities (Ex. DRA-5 at 20);
- SDG&E and SoCalGas should pay for all pressure testing of natural gas transmission lines installed since 1935. If SDG&E and SoCalGas chooses to replace, rather than test, pipelines installed after 1935, the companies should bear the costs, and the Commission should adopt a rate of return adjustment for those replacement pipelines (DRA Opening Brief at 4);
- does not oppose ratepayer funding of hydrotesting costs for 12 miles of transmission pipeline installed prior to 1935, but not at the excessive cost level SDG&E and SoCalGas proposes (DRA Ex. 2 at 78);
- does not oppose ratepayer funding of some valve upgrade work, but recommends SDG&E and SoCalGas's $122 million request be reduced to $52 million for the years 2012-2015 (Ex. DRA-4 at 9); and
- opposes all of SDG&E and SoCalGas's other attempts to impose system enhancement costs on ratepayers. Specifically, inclusion of costs for testing or replacing segments of distribution pipelines and non-criteria miles of transmission pipelines, for "mitigation" of pre-1946 construction methods, and for system

enhancement projects like methane detectors, fiber optic cables, information technology programs (Ex. DRA-2, at 29-42.)

4.2.2. Discussion

Because we adopt a balancing account approach to redress the inadequate budgets offered by SDG&E and SoCalGas, we need not address ORA's immediate concerns about forecasts; in fact we take a more conservative approach and we will use balancing accounts and reasonableness reviews. As discussed throughout, we are very concerned about costs imposed on ratepayers and we endeavor to strike a fair balance between ratepayers and shareholders. All of ORA's issues should be addressed in the reasonableness review for the balancing accounts.

4.2.3. The Utility Reform Network's (TURN) Summary

TURN was an active participant on Safety Enhancement and has raised some serious concerns in its Opening Brief as summarized below. Essentially TURN is concerned that SDG&E and SoCalGas has not provided a detailed well budgeted plan and that the Commission should not authorize rate recovery based on the level of detail in our record. TURN goes on to criticize, as vague and incomplete proposals, SDG&E and SoCalGas's specific requests for shut-off valves, and other related systems as a part of Safety Enhancement.

a) SDG&E and SoCalGas Safety Enhancement is based on preliminary cost estimates that the utilities themselves did not prepare and it reflects an incomplete analysis of which specific pipelines will be replaced rather than pressure-tested.
b) Under SDG&E and SoCalGas's proposal there would be no reasonableness review of the recorded costs associated with actual pressure tests or pipeline replacements.
c) The Commission should simultaneously begin a subset of pipeline safety programs while ensuring its ability to perform

the "comprehensive analysis" called for in D.11-06-017 before approving SDG&E and SoCalGas's proposed estimate of $1.7 billion in direct costs.

d) No recovery of testing or replacement costs in Phase 1 for post-1955 pipe segments should be approved now because these costs would not have been necessary if the SDG&E and SoCalGas Utilities had retained the pressure test records for those segments as directed by applicable standards and regulations. TURN argues these records are necessary to validate the safe operating pressure of transmission pipelines and are therefore critical for public safety. TURN argues California law therefore requires shareholders to absorb all the costs resulting from SDG&E and SoCalGas's violations of these important pipeline safety laws and standards.

e) For those segments with an identified manufacturing threat that are slated for replacement or remediation under Safety Enhancement, SDG&E and SoCalGas should be required to demonstrate that any testing that should have been conducted under federal Integrity Management requirements would not obviate the need to address the segment in here.

f) The Commission should defer action on SDG&E and SoCalGas's proposed Decision Tree (the process summarized in Ex. SCG-33-R and Attachment I) at this time; the ultimate determination of whether to pressure test or replace a line is a key decision for each and every pipeline that is a subject of the plan. TURN argues that the decision tree relies on "promised-but-not-unveiled" criteria that are more in the nature of still-evolving "guidelines that provide direction."

g) The Commission should reject the SDG&E and SoCalGas proposal that the current review of Safety Enhancement can serve as the likely exclusive opportunity for the agency to address the utilities' decision-making process. TURN proposes as a substitute the actual review of the actual decisions rather than the last-minute proposal for an advisory board, etc.

h) The Commission should deny rate recovery for the vast majority of the costs labeled "interim safety enhancement

measures," because they are in fact records search costs that should not be included in rates, arguing that recovery would be prohibited retroactive ratemaking, the costs are connected to past utility imprudence, and SDG&E and SoCalGas has failed to demonstrate the reasonableness of the costs.

i) The Commission should promote further exploration and development of in-line inspection technologies; because TURN believes the cost of an in-line inspection is substantially lower than the cost of a pressure test, if the Commission can determine that the results are similarly reliable for purposes of assessing the condition of an existing pipeline segment, the overall cost of the assessment would decline.

j) The Commission should adopt the principle that reliance on automatic shut-off valves is the preferred approach where feasible, and direct the Safety Division and the utilities to work together to reduce the number of remote controlled valves installed and thereby increase the potential cost-effectiveness of this element of Safety Enhancement.

k) The Commission should reject the utilities' proposal to include all pipeline segments designated "accelerated miles," and instead permit the SDG&E and SoCalGas Utilities to propose inclusion of "accelerated miles" on a project-specific basis once they have completed the engineering and planning for each project and seek Commission approval of that project.

l) The Commission should not adopt the SDG&E and SoCalGas proposals for "technology enhancements" due to their failure to present any evidence that the value to customers of the fiber optics and methane detection monitors warrants incurring the cost.

m) The Commission should not adopt the SDG&E and SoCalGas Utilities' proposal for pre-1956 pipeline "mitigation" measures at this time. The utilities have not demonstrated that these construction techniques are jeopardizing the safety of their pipeline systems, yet these measures represent the most expensive single component contained within the Proposed Case.

n) For the Enterprise Asset Management System the Commission should authorize the SDG&E and SoCalGas Utilities to track the related costs in their Pipeline Safety and Reliability Memorandum Accounts, subject to subsequent reasonableness review. In addition to cost-effectiveness and other more traditional reasonableness review issues, SDG&E and SoCalGas would need to demonstrate that the effort is incremental to the effort necessary to meet existing prudent record-keeping standards.

4.2.4. Discussion

Because we adopt a balancing account approach to redress the inadequate budgets offered by SDG&E and SoCalGas we need not address TURN's immediate concerns about forecasts and costs generally; in fact, we take a more conservative approach and we will use balancing accounts and reasonableness reviews. This is a greater protection than TURN's memorandum account proposal. We do discuss below and adopt the elimination of any incentive compensation. As discussed throughout, we are very concerned about costs imposed on ratepayers and we endeavor to strike a fair balance between ratepayers and shareholders. We do not agree that examining pre-1956 pipelines should be deferred. As discussed in the decision adopt the intended scope of work as summarized by the Decision Tree instead.

We believe that we have addressed TURN's programmatic concerns with Safety Enhancement even though we authorize more work than TURN recommends; for example, we authorize the accelerated Phase 1B work for the sake of efficiency and to ensure it is performed in a timely manner. Likewise, by adopting the analytical approach embodied in the Decision Tree we address all pipelines to ensure the system as a whole can be relied upon to be safe, and not just complying with the safety rules of a bygone era.

4.2.5. Southern California Generation Coalition - Summary

The Southern California Generation Coalition (Coalition) in its opening brief argues that the application and testimony lacked the necessary detail needed before the Commission could adequately conduct a review of the proposed expenditures and authorize rate recovery. The Coalition proposed that the Commission should "review on a case-by-case basis" utilizing an existing tool used by this Commission, the Expedited Application Docket procedure, each pipeline segment as a specific project within Safety Enhancement. (Coalition Opening Brief at 1.) As discussed below, we find merit with this concept, which we expand on in our balancing account methodology, but we do not adopt a series of mini-reviews by project or groups of projects. Preapproval would unduly delay Safety Enhancement and relieve SDG&E and SoCalGas of their obligation to exercise expert and prudent management.

4.2.6. Discussion

Safety Enhancement will take years to complete and will encompass numerous individual projects. It is only fair that ratepayers should have the benefit of detailed plans for this Commission to consider before authorizing or preapproving the expenditure of many hundreds of millions of dollars.

As set forth below, we find that SDG&E and SoCalGas have presented an adequate justification for Safety Enhancement at a conceptual level and we approve their Decision Tree (Attachment I) analytical approach. We find, however, that the budgets offered in support of this billion-dollar proposal are not sufficiently detailed to justify ratemaking pre-approval at this time. We authorize SDG&E and SoCalGas to file Tier 2 advice letters to establish balancing accounts and, in time, subsequent applications to demonstrate the

reasonableness of costs and recover those costs in rates. We authorize SDG&E and SoCalGas to proceed with Safety Enhancement projects that conform to the Decision Tree logic and track the costs of the work in a series of balancing accounts described below.

5. Safety Enhancement – Applying Section 454 Standard

5.1. Decision Tree

The Decision Tree is consistent with the priorities we set forth in D.11-06-017 and reflects a reasoned and orderly approach to testing or replacing natural gas pipeline in the SDG&E and SoCalGas systems. We find that SDG&E and SoCalGas have justified this approach to prioritizing the testing and replacement of natural gas pipeline systems. Therefore, we approve the Decision Tree and the analytical processes shown therein.

5.2. Ratemaking Proposal

During the evidentiary hearings SDG&E and SoCalGas produced two exhibits, Decision Tree the Reconciliation which explain and document both the review process (Decision Tree) proposed by SDG&E and SoCalGas and demonstrated in table form that the planning counted for the entire system (Reconciliation). This involved discussion and input from the parties and directions from the Judge. SDG&E and SoCalGas were eventually able to demonstrate that the Decision Tree does constitute a comprehensive plan to fully review and where necessary replace the natural gas system. The Reconciliation, and the time it took for the company to prepare it, illustrates both the complexity of the problem and that neither SDG&E nor SoCalGas, as of serving testimony or the evidentiary hearings, had sufficient management systems and personnel in place to show that they fully understand the flaws and weaknesses in the

implementation plan and they do not have a complete plan in place which would result in a safe and reliable natural gas system.

The witness for the applicants clearly demonstrated that the budget preparation performed for this proceeding by SDG&E and SoCalGas is rudimentary at best. The witness contrasted the company's proposal with the budget requirements used by the federal government for major procurement projects. The witness clearly showed that SDG&E and SoCalGas at best a "level 5" budget in a system where a level 5 budget is extremely preliminary, in fact rudimentary, and then only after careful planning and design does the budget progressively improve to levels 4, 3, 2, and finally level 1which is the most complete an advanced level of budgetary planning.[14]

In testimony, SDG&E and SoCalGas admitted:

> The estimates in our workpapers represent best available cost projections considering the nature and extent of projects that needed to be estimated for the PSEP, and the short timeframe available to develop them. SoCalGas and SDG&E acknowledge that these estimates are necessarily preliminary and often somewhat conceptual in nature. (Ex. SCG-21 at 1-2.)

The budget proposals of SDG&E and SoCalGas are clearly not sufficient to justify this Commission to authorize for ratemaking purposes. There are only two clear alternatives: authorize the program but make the companies fully liable for all risk of reasonableness review in an after-the-fact review of the final cost of the project; or require the companies to more fully develop budget

[14] "Class 5 or slightly better" characterization is based on a "recommended practice" produced by the Association for the Advancement of Cost Engineering.

proposals on a segment by segment basis for project construction, and seek commission approval based upon the level 1 quality of budgeting.

We therefore find that SDG&E and SoCalGas have not justified their proposed ratemaking for the costs of Safety Enhancement with their current showing. We direct SDG&E and SoCalGas to file new applications, consistent with today's decision, with detailed project descriptions and history and adequate cost records to justify recovery in rates.

5.3. Safety Enhancement Balancing Accounts

A balancing account is an appropriate regulatory tool where the scope of work is known and accepted as is here, Safety Enhancement as described by the Decision Tree and elsewhere in testimony by SDG&E and SoCalGas, etc., and we find it to be a sufficient project scope; but there is not a reasonable forecast of cost. A memorandum account is an alternative regulatory tool that would only be appropriate here if we could not find that Safety Enhancement was necessary and defined. Note that SDG&E and SoCalGas already have a memorandum account for Safety Enhancement where we have not found a scope of work to be reasonable nor have we found those costs to be reasonable for rate recovery.

SDG&E and SoCalGas must file Tier 2 Advice Letters to establish two new balancing accounts for each company: a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account. These accounts will record the revenue requirement for capitalized pipeline and other facilities and the actual expenses for Safety Enhancement that are not capitalized. The companies have the discretion to file annual cost recovery applications to review the reasonableness of completed capital projects included in the accounts and annual (or multi-year) expenses.

We believe that there is a major concern that we must not only ensure that the cost for these projects are reasonable based upon a competent and thorough analysis and design and budget process, but that also the project itself meets the overarching goal of enhancing the safety and reliability of the pipeline system.

We agree with TURN that SDG&E and SoCalGas's proposals as offered in this proceeding are incomplete and are an inadequate platform for authorizing construction or granting rate relief.

We are concerned however that TURN singles out pre-1946 pipeline mitigation because it is the most expensive i.e., extensive, component of SDG&E and SoCalGas's proposed mitigations. In fact, we are concerned that it is the oldest pipe, pre-1956, that might lack documentation; might be of the lowest quality of materials or construction, or even maintenance; and is least likely to meet current safety standards and therefore this pipe should be a focus of Safety Enhancement. Because we require SDG&E and SoCalGas to submit detailed records for all work performed for all testing and replacement, TURN's concerns can be addressed in the reasonableness review of the balancing accounts.

We also see no benefit to creating any oversight or advisory board to muddle the clear line of responsibility that rests solely with SDG&E and SoCalGas to competently manage and maintain the pipeline system. TURN is right to be concerned and we will not adopt such a board.

SDG&E and SoCalGas argues that ratepayers must bear all costs of compliance including testing and replacement of pipeline as a result of failing tests or lack of documentation. SDG&E and SoCalGas also asks for preapproval. ORA proposes an ex-post review, i.e., a reasonableness review after work is completed. SDG&E and SoCalGas argue:

> ex post reviews create an incentive for inefficient expenditure on the part of the utility. Rather than devoting resources to implementing an approved plan, the utility will focus on documenting the justification for each expenditure, and when forced to invest, will choose less-efficient systems with low capital costs (but possibly higher operating costs) to hedge the risk that they will not be able to recover the full capital cost of the investment. (SDG&E and SoCalGas Opening Brief at 56.)

We decline to adopt SDG&E and SoCalGas' inadequate cost forecasts and preapprove cost recovery. Instead our use of balancing accounts lets the companies exercise expert professional judgment and begin Safety Enhancement that is necessary to ensure a safe and reliable system.

5.4. Safety Division Oversight

The Commission's Safety Division (Safety Div.) has broad delegated authority to generally enforce the Commission's safety jurisdiction. Specific to SDG&E and SoCalGas's Safety Enhancement we delegate to Safety Div. the specific authority to directly observe and inspect the testing, maintenance and construction, and all other technical aspects of Safety Enhancement to ensure public safety both during the immediate maintenance or construction activity. and to ensure that the pipeline system and related equipment will be able to operate safely and efficiently for their service lives. Safety Div. may issue verbal requests for information which must be promptly answered, although Safety Div. must subsequently reduce all requests to writing. SDG&E and SoCalGas may not delay responding or wait for the written confirmation.

The Director of the Safety Div. is authorized to order SDG&E and SoCalGas to take such action as may be necessary to protect immediate public safety. Specifically, the Director is authorized to issue immediate stop work orders when necessary to immediately protect the public or to ensure public

safety in the future from possible errors or flaws in design, testing, maintenance and construction related to Safety Enhancement.

The Safety Div. must file and serve a copy of any stop work order in this proceeding no later than close of business of the Commission's next business day following the issuance of a stop work order. The Commission's Executive Director, and the Chief Administrative Law Judge, together shall ensure that SDG&E and SoCalGas, and all other parties to this proceeding, shall have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div. as may be feasible under the specific circumstances whenever Safety exercises its delegated authority.

6. Ratemaking Principles to be Applied in Reasonableness Applications

6.1. Summary

This decision does not propose or adopt any penalty for SDG&E or SoCalGas. We do however identify certain costs that should be absorbed by shareholders instead of ratepayers. Consistent with long-standing ratemaking principles, ratepayers will generally bear the reasonable costs for a safe and reliable natural gas transmission system. However, where imprudent actions by the gas system operator have led to unreasonable costs, we will assign those costs to shareholders.

6.2. Penalty, Disallowance or Consequences

California law, Commission practice and precedent, and common sense, all essentially require that before ratepayers bear any costs incurred by the utility that those costs must be just and reasonable. That is, the costs must have been prudently incurred by competent management exercising the best practices of the era, and using well-trained, well-informed and conscientious employees and

contractors who are performing their jobs properly. When that occurs, the commission can find the costs incurred by the utility to be just and reasonable and therefore, they can be recovered from ratepayers. When this is not the case however, the Commission can and must disallow those costs: that is unjust or unreasonable costs must not be recovered in rates from ratepayers.

SDG&E and SoCalGas presented an outside witness whose essential theme was that if the companies failed to recover any cost whatsoever this amounted to a penalty. We find this testimony completely unpersuasive and we accord it no weight. SDG&E and SoCalGas's witness would have us believe that any disallowance for unreasonable, imprudent costs, i.e., a regulatory disallowance, is a penalty. We do not believe that. A better descriptor would be "consequences" which can be defined as "a result or affect, typically one that is unwelcome or unpleasant," and the Oxford English Dictionary[15] uses the example "to bear the consequences," meaning "accept responsibility for the negative results or effects of one's choices or action." The Oxford English Dictionary also defines the word penalty as "a punishment imposed for breaking a law, rule, or contract."[16]

It is quite clear that any costs which may be disallowed in a subsequent proceeding are merely the proper consequences of imprudent actions by the

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[15] http://oxforddictionaries.com/?region=uk

[16] SDG&E and SoCalGas fare no better using the equally precise definitions found in Black's Law Dictionary, Sixth Edition, (1980). Penalty: "An elastic term with many shades of meaning; it involves the idea of punishment, corporeal or pecuniary, or civil or criminal, although its meaning is generally confined to pecuniary punishment." Disallowance: "To refuse to allow, to deny the need or validity of, to disown or reject." And, Consequence [singular not plural]: "The result following in natural sequence from an event which is adapted to produce, or to aid in producing, such result."

utility and do not constitute a penalty. In addition to those consequences however, the Commission has the authority and may in fact impose a penalty when the act that was imprudent also breaks a law, a rule, or contract. As discussed elsewhere in this decision we find that SDG&E and SoCalGas must bear some costs of Safety Enhancement but we impose no fines here based on this record.

6.3. Disallowance or Consequences

We find that SDG&E and SoCalGas has over 385 miles of pipeline which do not have documentation of a strength test of at least 125% of Maximum Allowable Operating Pressure.

The Decision Tree shows that at the time SDG&E and SoCalGas filed this application 385 miles were operated in Class 3 or 4 locations or High Consequence Areas that lacked documentation of pressure testing to a carrying capacity of 125% of Maximum Allowable Operating Pressure

Beginning on January 1, 1956 industry standards adopted, and later in 1961, the CPUC adopted, the first strength testing requirement for transmission pipelines. It is reasonable to require the shareholders of SDG&E and SoCalGas to absorb the costs of pressure testing facilities that were installed after January 1, 1956 but do not have an adequate pressure test record. In addition, if they are replaced without testing, the replacement cost should be reduced by the equivalent cost of testing. This is a reasonable consequence, consistent with ratemaking principles, not having the otherwise necessary records to validate the testing to then-current standards when the pipeline was installed.

We find that no later than as of January 1, 1956 industry standards made it a mandatory, non-retroactive, requirement for all gas pipeline segments operating over 20% Specified Minimum Yield Strength to be strength tested to a

level of 125% of Maximum Allowable Operating Pressure in Class 1 and 2 locations and 150% in Class 3 and 4 locations. The required test pressure had to be maintained for a period of no less than 1 hour after the pressure stabilized in all portions of the test sections (i.e., a static pressure test) prior to it entering service. Moreover, Section 841.417 of American Standard Gas Distribution and Transmission Piping System (ASA B31.8-1958), which was subsequently adopted by the Commission in General Order 112 required operating companies to at a minimum maintain: "for the useful life of each pipeline and main, records showing the type of fluid used for test and the test pressure."

Beginning on January 1, 1956 industry standards, and then on July 1, 1961, by General Order 112, SDG&E and SoCalGas have been required to strength test all pipeline segments, with a Maximum Allowable Operating Pressure of 20% of Specified Minimum Yield Strength or greater installed beyond these dates, and maintain records to demonstrate compliance. Beginning in 1956 industry standards, and then after July 1, 1961, Commission record keeping requirements evolved to require more specific strength test data to be documented. A prudent system operator should have retained records of these pressure tests. Therefore, for pipeline installed after January 1, 1956, where either SDG&E or SoCalGas cannot produce records that provide the minimum information required by these regulations to demonstrate compliance with the regulatory strength testing and records keeping requirements of industry standards and then General Order 112 and its revisions, as well the requirements of 49 CFR, Part 192 and its revisions beyond the effective date of Part 192, the shareholders must bear the costs of retesting these pipelines. Where replacement of the pipeline is planned rather than test existing pipelines, the system average cost of actual pressure testing should be an offset against the replacement costs of the pipelines for

revenue requirement purposes. In this way shareholders bear the costs of remedial pressure tests and ratepayers pay for all other costs of testing or replacing a pipeline.

The mileage shown in the Decision Tree is not directly matched in the Reconciliation. We therefore prepared the following table using the reconciliation to illustrate our adopted ratemaking treatment.

SDG&E and SoCalGas	**Pipeline Miles[(i)] Phase 1A/B**	**Pressure Testing & Replacement Cost Responsibility**
Pre-1946 Pipeline	269	Ratepayers Pay for Pressure Testing and/or New Pipeline
1946 Through 1955	442	Ratepayers Pay for Pressure Testing and/or New Pipeline
1956 Through June 1961	74	Company Pays for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline
July 1961 Through November 1970	29	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline
November 1970 to Present	74	When SDG&E or SoCalGas Cannot Produce Records Shareholders Pay for Pressure Testing & Absorbs Undepreciated Balances; Ratepayers Pay for New Pipeline

(i) Reconciliation

As we discussed elsewhere, for any pipeline abandonment or replaced that was installed after January 1, 1956, shareholders must absorb the remaining underappreciated book value. And, as also discussed, ratepayers bear the

revenue requirement of the net replacement costs however they benefit from having a new safe and reliable pipeline.

6.4. Missing Pressure Test Records

As already noted in section XX D.11-06-017, this Commission ended the exemptions from pressure testing and ordered all California natural gas transmission pipeline operators Implementation Plans The Commission found that 1970 federal and 1961 California requirements for pressure testing natural gas transmission pipeline applied only to new pipeline and exempted all existing in-service pipeline from the pressure test requirement. Accordingly, all pipeline installed after those dates should have been pressure tested, with the result that some of the oldest in-service natural gas pipeline has not been subjected to pressure testing to determine its Maximum Allowable Operating Pressure. Instead, the Maximum Allowable Operating Pressure for these untested pipeline segments is set by the highest recorded operating pressure on the segment.[17] (*See* D.12-12-030 at 11.)

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[17] 49 CFR §192.619(c).

The record shows that interim Federal standards were issued on November 7, 1968, as Part 190 of Title 49 of Code of Federal Regulations (CFR) and became effective on December 13, 1968. The Part 190 adopted the then existing State safety standards for gas pipelines as interim regulations. Effective November 12, 1970, the minimum Federal standards were adopted as Part 192 of Title 49 of the CFR, except for those provisions applicable to design, installation, construction, initial inspection, and initial testing. These exceptions remained in effect in Part 190 until March 13, 1971, when it was adopted into Part 192 and the existing interim standards (Part 190 of Title 49 CFR) were completely revoked.

The 49 CFR §192.517, recordkeeping and retention states: "Each operator shall make, and retain for the useful life of the pipeline, a record of each test performed under §§ 192.505 and 192.507. The record must contain at least the following information:

Footnote continued on next page

Essentially, from 1956 the industry standard has been for natural gas utilities to pressure test new facilities before pipelines enter service; then in 1961, the Commission adopted General Order 112 which required a pressure test before new pipelines entered service; and beginning in 1970 the federal government adopted a new Part 192 of Title 49 of the CFR rules that required two other pressure testing requirements before the pipeline entered into service. For new steel pipeline that is to operate at a hoop stress of 30 percent or more of Specified Minimum Yield Strength and 2) for new steel pipeline that will operate at hoop stress less than 30 percent of Specified Minimum Yield Strength but above 100-p.s.i.g. The reasonableness of SDG&E and SoCalGas's actions is dependent upon how well it complied with industry standards and state or federally adopted orders or regulations with respect to pressure testing and records retention for new pipeline facilities before entering service.

Therefore, in subsequent applications to recover the costs included in the Safety Enhancement related balancing accounts, SDG&E and SoCalGas must show that they complied with applicable regulations or standards when

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(a) The operator's name, the name of the operator's employee responsible for making the test, and the name of any test company used.

(b) Test medium used.

(c) Test pressure.

(d) Test duration[.]

(e) Pressure recording charts, or other record of pressure readings[.]

(f) Elevation variations, whenever significant for the particular test[.]

(g) Leaks and failures noted and their disposition."

installing the pipeline that now needs to be pressure tested or replaced. To the extent SDG&E or SoCalGas is not able to demonstrate such compliance, they will bear the cost because they will not be able to show that the costs of pressure testing that segment of pipeline are reasonable and thus properly assignable to ratepayers.

6.5. Safety Enhancement Reasonableness Applications

6.5.1. Minimum Filing Requirements

When SDG&E and SoCalGas file applications to demonstrate the reasonableness of Safety Enhancement they will bear the burden of proof that the companies used industry best practices and that their actions were prudent. This is not a "perfection" standard: it is a standard of care that demonstrates all actions were well planned, properly supervised and all necessary records are retained. At a minimum we would expect that SDG&E and SoCalGas could document and demonstrate an overview of the management of Safety Enhancement which might include: ongoing management approved updates to the Decision Tree and ongoing updates similar to the Reconciliation. The companies should be able to show work plans, organization charts, position descriptions, Mission Statements, etc., used to effectively and efficiently manage Safety Enhancement. There would likely be records of contractor selection controls, project cost control systems and reports, engineering design and review controls, and of course proper retention of constructions records, retention of pressure testing records, and retention of all other construction test and inspection records, and records of all other activities mandated to be performed and documented by state or federal regulations.

6.6. Incentive Compensation

SoCalGas proposes to apply an 18.17% incentive compensation plan overhead loader to its management and associated direct labor costs, and SDG&E proposes a 17.79% incentive compensation plan overhead loader to its management and other direct labor costs. (Ex SCG-10 at 122.)

TURN argues (Opening Brief at 82) that incentive compensation plans usual are designed to reward utility management and employees for meeting specific financial goals that contribute to the shareholders' earnings. TURN goes on that regardless of whether or not it is appropriate for ratepayers fund incentive compensation plans in the normal course of business, incentives for the pipeline safety enhancement plan is clearly not in the ratepayers' best interests. We agree this is a remediation program and no incentive compensation is warranted.

6.7. Pipeline Safety and Reliability Memorandum Accounts

Ordering Paragraph 3 in Dec. 12-04-021 in R. 11-02-019 allowed that:

> San Diego Gas and Electric Company and Southern California Gas Company must file a Tier 2 Advice Letter creating a memorandum account to record for later Commission ratemaking consideration the escalated direct and incremental overhead costs of its Pipeline Safety Enhancement Plan, as described in Attachment A to their January 13, 2012, filing, and costs of document review and interim safety measures as set forth in Attachment B to the January 13, 2012, filing.

On April 20, 2012, SDG&E and SoCalGas submitted Tier 2 Advice Letters 2106-G and 4359 to establish Pipeline Safety and Reliability Memorandum Accounts. Those Advice Letters were approved on May 18, 2012, with an effective date of May 20, 2012. As adopted, these accounts allow SDG&E and SoCalGas to record the actual incremental costs (i.e., operating and maintenance

and capital-related costs such as depreciation, income taxes, and return on investment.

7. Pipeline Safety and reliability Memorandum Account Recovery

SDG&E and SoCalGas along with the other respondents to R.11-02-019 were authorized to establish a Pipeline Safety and reliability Memorandum Account Recovery (Memo Account) in D.12-04-021:

> SDG&E and SoCalGas to create a memorandum account in which to record the incremental costs of implementing the Pipeline Safety Enhancement Plan. The Commission will consider whether such properly recorded costs are reasonable and incremental as well as which costs, if any, may be recovered from ratepayers in revenue requirement at a later time in the Triennial Cost Allocation Proceeding.

We believe that there is not a sufficient record on the costs recorded in the Memo Account to authorize recovery at this time. We find that the companies should not recover any incentive compensation or any costs associated with searching for test records of pipeline testing.

SoCalGas should file an application with testimony and work papers to demonstrate the reasonableness of the costs incurred which would justify rate recovery.

8. Summary of Rate Design and Cost Allocation Issues

This application began as a conventional "phase 2" application to address rate design and cost allocation issues in a proceeding trailing the triennial general rate cases. As already noted Safety Enhancement issues were added to the scope of the proceeding and in addition, parties litigated the question of whether the Safety Enhancement costs required any variance to the existing cost allocation methodology – that is, not allocating the eventual new and higher

costs of repaired or replaced pipeline components on the same methodology of the existing pipeline components but perhaps allocating them differently.

This section finds that parties reasonably entered into a settlement of the conventional issues and we therefore adopt it. However we are not persuaded that there is any merit to reallocating the costs of Safety Enhancement. Some parties suggest that safety is somehow a severable service from gas delivery: arguing in essence that the only reason we want the system to be safe is to not kill people if there is an explosion. We do of course want it to be safe and not kill people: but that is a prerequisite of having any pipeline. We therefore reject all proposed changes and find that the new costs of a safe system should be allocated exactly the same way the existing components to be repaired or replaced are allocated.

8.1. Conventional Issues Settlement

The active parties of this proceeding followed a consistent trend for San Diego and SoCalGas for a "phase 2 general rate case" by settling the conventional rate design and cost allocation issues that were the core of this original application (before adding in the Safety Enhancement issues). As discussed below we accept the settlement between these experienced and competent parties. An additional issue was raised by parties addressing the cost allocation of Safety Enhancement costs. There is no settlement on that issue and we will consider it separately.

SoCalGas, San Diego, DRA, TURN, Southern California Edison Company (SCE), Coalition, Indicated Producers, California Manufacturers and Technology Association, the City of Long Beach (Long Beach), and Southwest Gas Corporation (collectively, Phase 2 Settling Parties) filed a motion on March 27, 2013 asking the Commission to adopt the Phase 2 Settlement

Agreement[18] (Settlement) attached as Attachment III.[19] As a part of the Settlement the Settling Parties made the necessary recitals to comply with the Commission's settlement rules and summarized the key issues resolved in the settlement and provided all the necessary documentation to fully support an implementable settlement. Due to the length and complexity of the settlement we provide only a brief summary here but defer to the actual settlement as agreed to by the parties. Nothing in this summary interprets or limits the meaning of the settlement itself.

8.2. Settlement Summary

8.2.1. Demand Forecast

Settling Parties use, for the most part, the Applicant's updated demand forecast, including a complete update of 2011 demand data. This reflects a compromise between the litigation positions of various parties.

8.2.2. Cost Allocation

8.2.2.1. Long Run Marginal Cost

Settling Parties acknowledge that there exist numerous methodologies proposed by parties to determine marginal unit costs for the customer cost function. Through the negotiation process, however, the Settling Parties were able to identify certain outcomes that, if adopted as a package, would represent an acceptable resolution for each party involved in the settlement discussions. Accordingly, the Settling Parties have taken a "black box" approach to reaching

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[18] On April 15, 2013 Long Beach there was a further motion following approval by the Long Beach City Council to add Long Beach as a party.

[19] The settlement can also be found here: http://docs.cpuc.ca.gov/SearchRes.aspx?DocFormat=ALL&DocID=62909608

settlement and have agreed to certain modifications to their original cost allocation and rate proposals that are expressly intended to achieve these preferred outcomes.

8.2.2.2. Transition Adjustments

The Settling Parties agreed to a transition adjustment process to reduce the effect of "rate shock" as cost allocation moves towards fully cost-based rates.

8.2.3. Rate Design

8.2.3.1. Transmission Level Service

Settling Parties agree that, for customers who elect service under the Transmission Level Service Reservation Rate Option, quantities in excess of a customer's Daily Reservation Rate Quantity be billed at 115 percent of the Class Average Volumetric Rate. In addition, Settling Parties propose removal of the current requirement to exclude any subsequently allocated base margin portions of the Integrated Transmission Balancing Account from the Reservation Rate Usage Charge. Finally, Settling Parties propose that SoCalGas/SDG&E include in their next cost allocation application data on actual revenues from service provided under the Transmission Level Service Reservation Rate Option and actual volumes provided under that Option.

8.2.3.2. Throughput Risk

Settling Parties agree that noncore transportation revenue requirement continue to be subject to 100% balancing account treatment.

8.2.4. Backbone Operational Issues

8.2.4.1. Reservation Charge

Settling Parties agreed to a reservation charge to be adjusted annually in SoCalGas' Annual Regulatory Account Update filings.

8.2.4.2. Backbone Transmission Balancing Account Rate Adjustments

Settling Parties propose that the SDG&E and SoCalGas Backbone Transmission Service rates be subject to Backbone Transmission Balancing Account rate adjustments.

8.2.4.3. Volumetric Interruptible Backbone Transmission Service Rate

Settling Parties propose that SoCalGas' volumetric interruptible Backbone Transmission Service rate equal its reservation charge Straight Fixed Variable rate.

8.2.4.4. Functionalization of the SDG&E System

Settling Parties propose that the SDG&E transmission system continue to be classified as backbone.

8.2.4.5. Backbone-Only Rate

Settling Parties agree that SoCalGas withdraws its proposal for backbone-only rates from this proceeding, but it may address the question in later proceedings.

8.2.4.6. Modified Fixed Variable Rate Option

Settling Parties agree that SoCalGas' Modified Fixed Variable Rate Option be maintained with the Modified Fixed Variable volumetric rate designed so that 100% load factor Modified Fixed Variable rate equals the Straight Fixed Variable "100% Reservation" rate for Backbone Transmission Service.

8.2.5. Storage

8.2.5.1. Honor Rancho Cost Recovery

Settling Parties propose that SoCalGas receive full rate recovery of its Honor Rancho Expansion Project costs.

8.2.5.2. Extension of the 2009 Phase 1 Settlement Agreement

Settling Parties propose extending the 2009 Phase 1 Settlement Agreement through the end of 2015.

8.2.6. Southern System

Settling Parties propose all Southern System issues be considered in a separate application filed by SDG&E and SoCalGas.

8.3. Applying the Settlement Rules

We find as required by Rule 12.1 of the Commission's Rules of Practice and Procedure (Rules),[20] the proposed settlement is reasonable in light of the whole record, consistent with law, and in the public interest. The settled positions are a balance between the positions as otherwise litigated in the prepared testimony of San Diego and SoCalGas, DRA, and the other parties that served testimony or otherwise actively participated in phase 2. We therefore adopt the attached settlement (Attachment I) without further discussion of the merits of the individual components. No item settled in this proceeding is dispositive of the appropriate rate treatment in subsequent proceeds. (Rule 12.5.)

We find that the parties had a sound and thorough understanding of the application, and all of the underlying assumptions and data included in the

[20] http://docs.cpuc.ca.gov/WORD_PDF/AGENDA_DECISION/143256.PDF

record. This level of understanding of the application and development of an adequate record is necessary to meet our requirements for considering any settlement. These requirements are set forth in Rule 12.1(a)[21] which states:

> Parties may, by written motion any time after the first prehearing conference and within 30 days after the last day of hearing, propose settlements on the resolution of any material issue of law or fact or on a mutually agreeable outcome to the proceeding. Settlements need not be joined by all parties; however, settlements in applications must be signed by the applicant….
>
> When a settlement pertains to a proceeding under a Rate Case Plan or other proceeding in which a comparison exhibit would ordinarily be filed, the motion must be supported by a comparison exhibit indicating the impact of the settlement in relation to the utility's application and, if the participating staff supports the settlement, in relation to the issues staff contested, or would have contested, in a hearing.

Rule 12.1(d) provides that:

> The Commission will not approve settlements, whether contested or uncontested, unless the settlement is reasonable in light of the whole record, consistent with the law, and in the public interest.

Rule 12.5 limits the future applicability of a settlement:

> Commission adoption of a settlement is binding on all parties to the proceeding in which the settlement is proposed. Unless the Commission expressly provides otherwise, such adoption does not constitute approval of, or precedent regarding, any principle or issue in the proceeding or in any future proceeding.

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[21] All referenced Rules are the Commission's Rules of Practice and Procedure. (http://docs.cpuc.ca.gov/published/RULES_PRAC_PROC/70731.htm)

The parties clearly demonstrated that they understood the issues, and engaged in a negotiated "give and take" which satisfied the needs of their respective constituents. We therefore find that the proposed "phase 2" settlement comports with Rule 12.1(d), and it is "reasonable in light of the whole record, consistent with law, and in the public interest."

9. A Ruptured Pipe Delivers No Gas – Allocating Safety Enhancement Costs

9.1. Summary of Cost Allocation for Safety Enhancement

Several parties suggest that the Safety Enhancement costs do not contribute to gas delivery service; the costs only reduce the risk of death and injury to people who live or work adjacent to a pipeline should that pipeline rupture or fail. We observe that a ruptured pipeline delivers no gas – to anyone, business or individual – and as we discuss in the Safety Enhancement portion of this decision enhanced safety is also, equally, enhanced reliability. An un-ruptured pipeline (properly constructed and tested) can usually be expected to deliver gas in a reliable fashion to businesses or individuals. We therefore decline to modify any cost allocation to shift Safety Enhancement costs from one customer class to another. The cost of the new safe component should be allocated just as its predecessor was allocated; SDG&E and SoCalGas have shown no persuasive justification to deviate from the existing cost allocation and rate design principles.

9.2. Options for Allocating Safety Enhancement

SDG&E and SoCalGas propose that costs should be allocated to customer classes based on cost causality; we should avoid rate shock (i.e. rapid or large increases) and keep a customer perspective; and we should maintain consistency with current practice whenever possible. (Ex. SCG-12.) SDG&E and SoCalGas's

witness specifically argued that the fundamental principle to be followed in allocating costs among customer groups is cost causation which:

> Cost causation seeks to determine which customer or group of customers causes the utility to incur particular types of costs. It is therefore necessary to establish a linkage between a utility's customers and the particular costs incurred by the utility in serving those customers. The essential element in the selection and development of a reasonable cost allocation methodology is the establishment of relationships between customer requirements, load profiles and usage characteristics, and the costs incurred by the utility in serving those requirements. (*Ibid.*)

As a general rule we would agree with SDG&E and SoCalGas, although we would list consistency ahead of avoiding rate shock as an allocation principle, which is more of a mitigation measure; i.e., we would always want to move to fully allocated costs even if we did so in incremental steps.

Settling Parties suggest that there are two basic ways of allocating Safety Enhancement program costs. In their briefs they argue for their preference of these two methods as we discussed below it is apparent the parties argued based upon how they perceive the cost of Safety Enhancement affecting their rates.

The first of these two approaches is the functionalized approach where the costs are allocated to a particular component of gas service and then in turn finally allocated to different customer class based upon that class's use of each particular component of service. TURN and DRA argue for the functional approach. Coalition argues for different methodology, it proposes that Safety Enhancement related are essentially a one-time remediation rather than an ongoing cost of providing service and should therefore be allocated differently. This party and others argue that the cost should be allocated on an Equal Percentage of Authorized Margin. They argue that Safety Enhancement is

fundamentally different from SDG&E and SoCalGas's Transmission Integrity Management Program that they argue is an ongoing program and that Safety Enhancement should be allocated differently. The Coalition calls this an unintended negative consequence and further argues that a functional allocation leads to an inappropriate rate shock and anti-competitive result. (Coalition Opening Brief at 2.)

The Coalition also argues that some cost must be allocated to Backbone Transmission Service customers. It argues that the customers should receive an allocation regardless of whether we adopt a functional method or an equal percentage method because the Coalition believe that a significant portion of Safety Enhancement costs will be incurred on facilities that provide Backbone Transmission Service. (Coalition Opening Brief at 3.) They make a compelling point that this would benefit other customers regardless of the allocation methodology.

9.3. Retaining Existing Cost Allocation and Rate Design

Because no Safety Enhancement costs are directly incurred as a result of this decision there is no immediate change to implement for cost allocation and rate design. However, we agree with the Coalition that Backbone Transmission Service customers should in the future be allocated Safety Enhancement related costs to the extent that any pipeline components modified or replaced by Safety Enhancement that are used to provide service to Backbone Service customers.

We disagree with the Coalition's assumption that Safety Enhancement is somehow a one-time cost. As required by Pub. Util. Code § 451, safe operation of a natural gas system is the operator's long-standing and continuing responsibility, not a one-time event. Moreover, an unreliable or ruptured pipeline delivers no gas to any class of customer. No persuasive justification has

been presented to apply different cost allocation or rate design principles to Safety Enhancement costs and we decline to adopt a different approach. The cost of these new facilities that replace existing pipeline facilities should be allocated in the same manner as the old facilities were allocated.

10. Categorization and Need for Hearing

This proceeding was categorized as ratesetting and evidentiary hearings were held on phase 1. Safety Enhancement and phase 3, cost allocation issues for the costs of Safety Enhancement. Phase 2 cost allocation, marginal cost and rate design was settled without the need for hearings.

11. Comments on Proposed Decision

The proposed decision of the Administrative Law Judge (Judge) in this matter was mailed to the parties in accordance with Section 311 of the Public Utilities Code and comments were allowed under Rule 14.3 of the Commission's Rules of Practice and Procedure. Comments were filed on _____, and reply comments were filed on _____ by _____.

12. Assignment of Proceeding

Michel Florio is the assigned Commissioner and Douglas Long is the assigned Judge and Presiding Officer in this proceeding.

Findings of Fact

1. SDG&E and SoCalGas are public utilities that operate natural gas pipeline transmission systems subject to the jurisdiction of this Commission.

2. There is an identified need to enhance the safety and reliability of the natural gas pipeline transmission systems operated by SDG&E and SoCalGas. This may include the testing and/or replacement of many segments of these systems.

3. In D.11-06-017, the Commission declared an end to historic exemptions from pressure testing for natural gas pipeline and ordered all California natural gas system operators to file Natural Gas Transmission Pipeline Testing Implementation Plans.

4. Decision 12-12-030 requires that natural gas pipelines must be made safe and reliable.

5. There are 385 miles identified in the Decision Tree that lack documentation of pressure testing.

6. Industry standards for testing and record retention changed as of January 1956.

7. SDG&E and SoCalGas did not present sufficient project details and cost justification for their proposed ratemaking treatment of Safety Enhancement costs.

8. The Safety Enhancement cost forecasts are inadequate for cost recovery preapproval.

9. The proposed ratemaking to allocate all Safety Enhancement costs to ratepayers was not justified.

10. Balancing accounts will allow SDG&E and SoCalGas to begin Safety Enhancement testing, maintenance, and new construction.

11. Balancing accounts will allow SDG&E and SoCalGas an opportunity to recover reasonable costs for Safety Enhancement later.

12. The companies proposed inclusion of incentive compensation in the costs of Safety Enhancement.

Rate Design Settlement

13. The active parties in phase 2 have reached a settlement on all outstanding rate design issues.

14. The settlement by all parties comports with the Commission's settlement rules and resolves all issues.

Cost Allocation for Safety Enhancement

15. The proposed allocation of costs of the new pipeline, which replaces the existing pipeline, would reallocate costs between customer classes with no change in service.

16. The existing cost allocation, as settled, allocates costs to customer classes based upon the costs incurred to serve those customers.

17. Safety Enhancement does not change the service provided to customers although it does likely improve reliability by replacing existing pipelines with new pipelines that meet industry and Commission required safety standards.

18. The ratepayers will be served by a safe and reliable system with new components that will operate for decades.

Conclusions of Law

1. As required by § 451 all rates and charges collected by a public utility must be "just and reasonable," and a public utility may not change any rate "except upon a showing before the commission and a finding by the commission that the new rate is justified," as provided in § 454.

2. Pub. Util. Code § 451 requires safe operation of a natural gas system. It is a long-standing and continuing responsibility, not a one-time obligation.

3. The burden of proof is on SDG&E and SoCalGas to demonstrate that it is entitled to the relief sought in this proceeding, including affirmatively establishing the reasonableness of all aspects of the application.

4. The standard of proof that SDG&E and SoCalGas must meet is that of a preponderance of evidence, which means such evidence as, when weighed with that opposed to it, has more convincing force and the greater probability of truth.

5. The Decision Tree analysis used to evaluate the existing pipeline network for safety, documentation, and reliability, is a reasonable but not final process.

6. It is reasonable to expect SDG&E and SoCalGas to exercise prudent management and use industry best practices. Industry best practices had changed by January 1, 1956 and SDG&E and SoCalGas should not have waited for Commission rules to be up-dated.

7. The Decision Tree should be approved.

8. The Safety Div. should oversee Safety Enhancement to ensure public safety during the design, maintenance and construction phase as well as ensure safety in the future operations of the modified pipeline systems.

9. The Commission has the authority to delegate stop work order authority to Safety Div.

10. The Commission must ensure parties have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div.

11. The proposed ratemaking for Safety Enhancement should not be approved.

12. It is reasonable for SDG&E and SoCalGas' shareholders to absorb the portion of the Safety Enhancement costs that were caused by any prior imprudent management. DG&E and SoCalGas should absorb the costs of pressure testing where the company cannot produce records that provide the minimum information to demonstrate compliance with the industry or regulatory strength testing and records keeping requirements of industry standards beginning in January 1, 1956, General Order 112 and its revisions, as well the requirements of 49 CFR, Part 192 and its revisions beyond the effective date of Part 192.

13. Where pipelines are replaced without testing SDG&E and SoCalGas should absorb an amount equal to the average cost of pressure testing where the company cannot produce pressure test records after January 1, 1956.

14. SDG&E and SoCalGas should absorb the un-depreciated balances of any abandoned pipelines.

15. The inclusion of incentive compensation in the costs of Safety Enhancement was not justified.

16. SDG&E and SoCalGas should be authorized to file and serve subsequent applications to recover the costs recorded in the Safety Enhancement balancing accounts.

17. Subsequent applications to review the Safety Enhancement Capital Cost Balancing Accounts and a Safety Enhancement Expense Balancing Accounts should be filed with sufficient detail to justify the proposed construction and its costs.

18. It is reasonable to require the ratepayers to pay for the costs to repair or rebuild the system.

19. A valid record of a pipeline pressure test must include all elements required by regulations in effect at the time the test was conducted.

20. It is reasonable to require SDG&E and SoCalGas to comply with 49 CFR Part 192, subpart J pressure test specifications when conducting pressure tests pursuant to the plan approved herein.

21. SDG&E and SoCalGas have justified the concept to "accelerate" replacing certain pipeline segments located in various locations outside the High Consequence Areas but adjacent to other locations which warrant replacement, or with economic or engineering supporting rationale, within Phase 1A.

22. SDG&E and SoCalGas costs incurred prior to the effective date of today's decision should be subject to approval based on a reasonableness review of the Pipeline Safety and Reliability Memorandum Accounts.

23. The reasonableness issues identified by ORA and TURN will be addressed in the reasonableness review applications for the balancing accounts.

24. There is no justification of any incentive compensation component to be added into the costs of Safety Enhancement.

Rate Design Settlement

25. The Commission has the authority to adopt a settlement when it is reasonable in light of the whole record, consistent with law, and in the public interest.

26. The proposed rate design settlement is reasonable in light of the whole record, consistent with law, and in the public interest and should be adopted.

Cost Allocation for Safety Enhancement

27. The existing cost allocation methodology is reasonable for the costs of Safety Enhancement because these costs are necessary to safely and reliably supply natural gas to existing customers in the same manner as the existing system serves customers.

28. This decision should be effective today.

29. This proceeding should be closed.

O R D E R

IT IS ORDERED that:

1. We adopt the overall plan for Safety Enhancement to ensure the safety and reliability of San Diego Gas & Electric Company and Southern California Gas Company as embodied in the Decision Tree (attachment I) and Reconciliation (Attachment 2).

2. We authorize San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) to begin work as described in their Safety Enhancement Plans with costs recorded in balancing accounts and subject to refund pending a subsequent reasonableness review.

3. The Director of the Commission's Consumer Protection and Safety Division, or designee, (Safety Div.) is delegated the following specific authority to act in addition to all existing general authority delegated to staff:

(a) Safety Div. may inspect, inquire, review, examine and participate in all activities of any kind related to Safety Enhancement. San Diego Gas & Electric Company (SDG&E), Southern California Gas Company (SoCalGas), all of their contractors shall immediately provide any document, analysis, test result, plan, of any kind related Safety Enhancement as requested by Safety's staff or contractors. Safety must subsequently confirm all requests in written form, however all responses to must be immediate.

(b) Safety Div. may issue immediate stop work orders to SDG&E and SoCalGas, and all of their contractors when necessary to protect public safety. SDG&E and SoCalGas must comply immediately.

(c) The Commission's Executive Director, and the Chief Administrative Law Judge, together shall ensure that SDG&E and SoCalGas, and all other parties to this proceeding, shall have timely procedural opportunities for a review of any action or stop work orders issued by Safety Div. as may be feasible under the specific circumstances whenever Safety exercises its delegated authority.

(d) Safety Division must formally file a copy of any Stop Work Order in this proceeding by the close of business on the workday following its issuance to either SDG&E and SoCalGas, or any contractors.

4. Within 30 days of the effective date of this decision San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) must file Tier 2 Advice Letters to establish a Safety Enhancement Capital Cost Balancing Account and a Safety Enhancement Expense Balancing Account to record the expenditures incurred pursuing the Safety Enhancement proposals adopted in Ordering Paragraph 1.

5. Cost recovery of the Pipeline Safety and Reliability Memorandum Accounts for San Diego Gas & Electric Company (SDG&E) and Southern California Gas Company (SoCalGas) will be reviewed for reasonableness in a new application or applications. SDG&E and SoCalGas are limited to the recovery of only those costs that directly contribute to the implementation of Safety Enhancement.

6. The comprehensive rate design settlement (Attachment 3) between San Diego Gas & Electric Company (SDG&E) and all active parties and adopts a rate design settlement between Southern California Gas Company (SoCalGas) and all

active parties is adopted. This settlement resolved all issues except the rate design proposals for SDG&E and SoCalGas' Safety Enhancement costs.

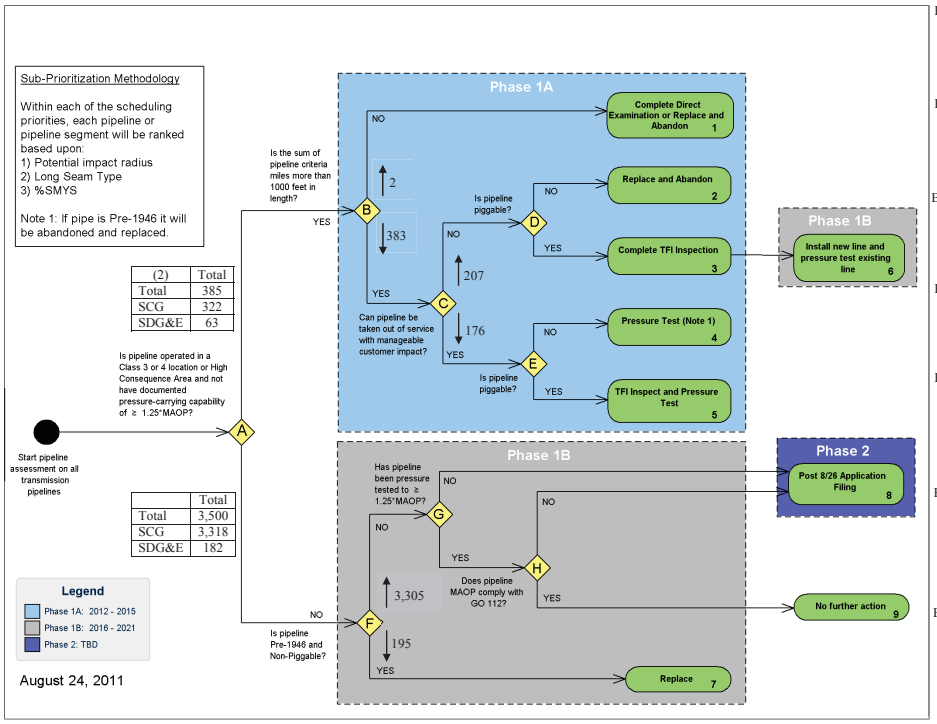
7. We reject all proposed modifications to the existing cost allocation methodology proposed by San Diego Gas & Electric Company and Southern California Gas Company and the parties for Safety Enhancement costs. Safety Enhancement costs will be allocated consistent with the existing cost allocation and rate design for the companies.

8. Application 11-11-002 is closed.

This order is effective today.

Dated _____, at San Francisco, California.

Attachment I



(1)	Total
Total	3,885
SCG	3,640
SDG&E	245

(2)	Total
Total	385
SCG	322
SDG&E	63

	Total
Total	3,500
SCG	3,318
SDG&E	182

Box 1

(3)	Total	Crit.	Accel.
Total	2	2	0
SCG	2	2	0
SDG&E	0	0	0

Box 2 (8)

(4)	Total	Crit.	Accel.
Total	287	177	110
SCG	238	144	94
SDG&E	49	32	17

Box 3

(5)	Total
Total	54
SCG	0
SDG&E	54

Box 6 (pressure test existing line)

(5)	Total	Crit.	Accel.
Total	45	30	15
SCG	0	0	0
SDG&E	45	30	15

Box 4

(6)	Total	Crit.	Accel.
Total	25	12	13
SCG	24	11	13
SDG&E	1	1	0

Box 5

(6)	Total	Crit.	Accel.
Total	334	164	170
SCG	334	164	170
SDG&E	0	0	0

Box 8/9

(7)	Total
Total	3,305
SCG	3,123
SDG&E	182

Some mileage prioritized for Box 8/9 is proposed to be included (accelerated) into the Phase 1A scope
- *110 miles in Box 2*
- *13 miles in Box 4*
- *170 miles in Box 5*
- *15 miles in Box 6*

Box 7

	Total
Total	195
SCG	195
SDG&E	0

1) SoCalGas and SDG&E's DOT "Annual Report for Calendar Year 2011 Natural or Other Gas Transmission and Gathering Systems".
2) Amended Application. Table IV- 4. Pg 50.
3) Amended Application. Table IV-5. Pg 53 and Workpaper page WP-IV-5 of 12.
4) Amended Application. Table IV-5. Pg 53.
   a. Mileage numbers don't exactly match Table I-1 due to: (1) distribution miles inadvertently in amended filing, and 2) rounding of numbers
5) L#1600 - 54 miles of existing L#1600 to be TFI'd (Amended Workpapers, WP-IX-1-43). After 54 new miles installed in Phase 1B (Amended Workpapers, WP-IX-1-34), then 45 miles of existing L#1600 will be pressure tested in Phase 1B (Amended Workpapers, WP-IX-1-17)
6) Sempra Amended Application. pg 5. Table I-1
   a. Mileage numbers don't quite match Table I-1 due to: (1) The inclusion of DOT defined distribution , and 2) rounding of numbers
7) Approximately 963 miles at SCG and 79 miles at SDGE were placed into service after 1970.
8) Miles included in Box 2 have changed when compared to the original decision tree due to the removal of all distribution segments. The segments, however, remain a part of SoCalGas/SDG&E proposal as explained in SCG-12. They have been removed from this spreadsheet because they are not DOT defined transmission lines.

(End of Attachment I)

Attachment II

SCG	Phase 1A																		Phase 1B							Phase 2	Total Existing Transmission Miles[3]
	Replacement						Pressure Test						Abandon[1]					Wrinkle Bends	Replacement	Pressure Test					Wrinkle Bends		
	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			
Pre-1946	0	0	0	28	15	7	3	0	0	39	31	0	0	0	0	1	0	706	195	0	0	0	0	0	1204	0	264
1946 - 1954	0	0	0	62	38	8	6	0	0	112	112	0	0	0	0	15	29	3256	0	0	0	0	0	0		449	824
1955 - June 1961[5]	0	0	0	24	2	3	0	0	0	14	17	0	0	0	0	0	0	0	0	0	0	0	0	0		948	1006
July 1961 - Nov 1970[6,7]	1	0	0	9	1	1	1	0	0	2	6	0	0	0	0	0	0	34	0	0	0	0	0	0		546	566
Nov 1970 - Present[4]	2	1	0	4	4	4	2	0	0	4	4	0	0	0	0	0	0	0	0	0	0	0	0	0	0	963	984
	3	1	0	127	59	23	12	0	0	170	170	0	0	0	0	16	29	3996	195	0	0	0	0	0	1204	2907	3644

SDG&E	Phase 1A																		Phase 1B[2]							Phase 2	Total Existing Transmission Miles[3]
	Replacement						Pressure Test						Abandon					Wrinkle Bends	Replacement	Pressure Test					Wrinkle Bends		
	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			
Pre-1946	0	0	0	4	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		0	4
1946 - 1954	10	0	0	9	0	1	0	0	0	0	0	0	0	0	0	4	0	0	0	0	0	0	30	15	0	0	68
1955 - June 1961	2	2	0	13	0	2	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		57	74
July 1961 - Nov 1970[7]	1	0	0	1	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0		14	17
Nov 1970 - Present[4]	0	1	0	1	0	0	0	0	0	1	0	0	0	0	0	0	0	0	0	0	0	0	0	0	0	79	83
	13	4	0	28	1	4	0	0	0	1	0	0	0	0	0	5	0	0	0	0	0	0	30	15	0	150	246

Total SEu	Phase 1A																		Phase 1B							Phase 2	Total Existing Transmission Miles[3]
	Replacement						Pressure Test						Abandon					Wrinkle Bends	Replacement	Pressure Test					Wrinkle Bends		
	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria	DOT Distribution	Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			Category 1	Category 2	Category 3	Category 4 Criteria	Category 4 Non-Criteria			
Pre-1946	0	0	0	32	15	7	3	0	0	39	31	0	0	0	0	1	0	706	195	0	0	0	0	0		0	268
1946 - 1954	10	0	0	71	38	9	6	0	0	112	112	0	0	0	0	20	29	3256	0	0	0	0	30	15	1204	450	892
1955 - June 1961	2	2	0	37	2	5	0	0	0	14	17	0	0	0	0	0	0	0	0	0	0	0	0	0		1005	1080
July 1961 - Nov 1970	2	0	0	10	1	2	1	0	0	2	6	0	0	0	0	0	0	34	0	0	0	0	0	0		560	583
Nov 1970 - Present[4]	2	2	0	5	4	4	2	0	0	4	5	0	0	0	0	0	0	0	0	0	0	0	0	0	0	1042	1067
	17	5	0	155	60	27	12	0	0	171	171	0	0	0	0	21	29	3996	195	0	0	0	30	15	1204	3057	3890

Notes:

Accelerated mileage includes Category 1, Category 2, Category 3, and Category 4 Non-Criteria mileage in Phase 1A

[1] 36 miles of Line 41-6000-2 is proposed to be abandoned and replaced with Line 6914 extension (28 miles). Various abandonments make up the remained of 8 miles at SCG and 1 mile at SDGE.

[2] For L#1600, 45 miles will be pressure tested after 54 new (replacement) miles installed in phase 1B.

[3] Total Existing Transmission Miles per the 2011 DOT Report.

Note: Total pre-1946 transmission mileage for SCG does not include Line 1026, which underwent a reduction in MAOP in 2011 resulting in its operation at less than 20% SMYS. Mileage for Line 1026 (approx. 40 miles) is in the PSEP filing for replacement in Phase 1B.

[4] Costs for 18 miles (16 SCG; 2 SDGE) of post-1970 Category 4 pipeline segments excluded from PSEP filing. Post-1970 Category 1 and 2 segments (which have sufficient record of a pressure test) included in PSEP scope for cost/project efficiency.

[4] 1049 miles of the 1067 total post 70 transmission miles are compliant with GO112 pressure testing and record keeping requirements. Compliant miles may change once Phase 2 records review is completed.

[5] 4 miles of category 4 criteria that were initially included in July 1961 - Nov 1970 have been subsequently determined to be pre-1960. This sheet reflects this increase - 3 miles are Replacement and 1 miles are Pressure Test.

[6] 2.7 miles of 1961 - 1970 have documentation that would have met the requirement of GO112. They, however, did not have sufficient documentation of a 1.25 X MAOP to satisfy SoCalGas & SDGE's screening process for their April report. All 2.7 miles were from Pressure Test.

[7] 1 mi at SCG and 0.5 mi at SDGE had records verified that indicate segments are no longer Category 4 (1 mile from category 4 non criteria moved to category 1 - all in Replacement)

Definitions:

Criteria = Populated Areas = Class 3 & 4 and Class 1 & 2 HCA's (high consequence areas)

Non Criteria = Non populated areas = Class 1 & 2 Non HCA's

Category 1 = Pipe for which there is sufficient documentation of a pressure test *with water* of at least 1.25 MAOP (may or may not meet current pressure test duration and record keeping requirements - aka "subpart J" requirements)

Category 2 = Pipe for which there is sufficient documentation of a pressure test *with gas* of at least 1.25 MAOP (may or may not meet current pressure test duration and record keeping requirements - aka "subpart J" requirements)

Category 3 = Pipe for which documentation validates that the highest in-service operating pressure is at least 1.25 X the current MAOP.

Category 4 = Pipe for which there is not sufficient documentation of a pressure test of at least 1.25 MAOP.

DOT Distribution = Pipe whose MAOP is operating at less than 20% SMYS. Shown in this table because 27 miles of distribution pipe are interspersed with transmission pipelines and are included in our PSEP plan.

Source Data: DAO - 10 Data Response - Encompasses workpaper segments with install year added for each work segment.

Disclaimer: Due to rounding the mileage numbers shown on this sheet may not exactly match the mileage amounts in the amended testimony.

Note: Records have been found since the filing of Testimony for 3 of the 8 miles of post 70 pipe Category 4 Criteria (4 miles replacement and 4 miles hydrotest) pipe.

(End of Attachment II)

Attachment III

BEFORE THE PUBLIC UTILITIES COMMISSION
OF THE STATE OF CALIFORNIA

In the Matter of the Application of San Diego Gas & Electric Company (U 902 G) and Southern California Gas Company (U 904 G) for Authority to Revise Their Rates Effective January 1, 2013, in Their Triennial Cost Allocation Proceeding	A.11-11-002 (Filed November 1, 2011)

SOUTHERN CALIFORNIA GAS COMPANY, SAN DIEGO GAS & ELECTRIC COMPANY, DIVISION OF RATEPAYER ADVOCATES, THE UTILITY REFORM NETWORK, SOUTHERN CALIFORNIA EDISON COMPANY (U 338 E), SOUTHERN CALIFORNIA GENERATION COALITION, INDICATED PRODUCERS, CALIFORNIA MANUFACTURERS AND TECHNOLOGY ASSOCIATION, THE CITY OF LONG BEACH, AND SOUTHWEST GAS CORPORATION (U 905 G) PHASE 2 SETTLEMENT AGREEMENT

Pursuant to Article 12 of the Commission's Rules of Practice and Procedure, Southern California Gas Company (SoCalGas), San Diego Gas & Electric Company (SDG&E) (jointly SoCalGas/SDG&E or Applicants), the Division of Ratepayer Advocates (DRA), The Utility Reform Network (TURN), Southern California Edison Company (SCE), Southern California Generation Coalition (SCGC), Indicated Producers (IP), California Manufacturers and Technology Association (CMTA), the City of Long Beach,[1] and Southwest Gas Corporation (Southwest Gas) (collectively referred to hereafter as the Settling Parties) respectfully submit to the Commission this Settlement Agreement (Settlement). In this Settlement, the Settling Parties provide to the Commission a recommended resolution of certain issues in Phase 2 of this proceeding.

[1] The Settlement must be approved by the City of Long Beach City Council which approval is pending.

I
REASONABLENESS OF THE SETTLEMENT

The Settling Parties submit that this Settlement complies with the Commission's requirements that settlements be reasonable, consistent with law, and in the public interest. The Settling Parties have recognized that there is risk involved in litigation, and that a party's filed position might not prevail, in whole or in part, in the Commission's final determination. The Settling Parties have reached compromise positions that they believe are appropriate in light of the litigation risks. This Settlement reflects the Settling Parties' best judgments as to the totality of their positions and risks, and their agreement herein is explicitly based on the overall results achieved.

II
SETTLEMENT TERMS AND CONDITIONS

A. Effective Date; Term of Agreement

1. The Effective Date of this Settlement is the date upon which the Commission approves the Settlement. The rates set forth in this Settlement shall go into effect upon the date(s) established by the Commission.
2. The term of the Settlement shall extend from the date upon which the Commission approves the Settlement through implementation (tariff approval) of the next SoCalGas and SDG&E TCAP.

B. Settlement Terms

1. Demand Forecast

a. SoCalGas/SDG&E rates shall be based on the SoCalGas/SDG&E January 22, 2013 updated demand forecast (Appendix A to this Settlement).

2. Cost Allocation

a. Parties proposed a range of methodologies to determine marginal unit costs for the customer cost function from use of the Rental Method to New Customer Only with replacement cost adder proposals. For purposes of this Settlement, the marginal unit costs for the customer cost function are as shown in Appendix B. Illustrative rates are provided in Appendix C.

b. The transition adjustments for the core proposed by SoCalGas and SDG&E shall be adopted with the resulting cost of the transition adjustment being recovered as proposed by SoCalGas and SDG&E. The transition adjustments for the EG-D Tier 1 and EG-D Tier 2 rate classes shall be phased out by December 31, 2015 with the rates increasing by the same percentage each year 2013-2016. The cost of the transition adjustment shall be recovered from the TLS and NCCI-D rate classes proportionately by volume, except that half of the cost that would be recovered from the NCCI-D rate class shall be reallocated for recovery from the TLS rate class.

3. Rate Design

a. For customers that elect service under the TLS Reservation Rate Option, quantities in excess of a customer's Daily Reservation Rate Quantity shall be billed at 115 percent of the Class Average Volumetric Rate.

b. SoCalGas shall remove the requirement to exclude any subsequently allocated base margin portions of the ITBA from the Reservation Rate Usage Charge.

c. SoCalGas/SDG&E shall include in their next Triennial Cost Allocation Application data on actual revenues from service provided under the TLS Reservation Rate Option and actual volumes provided under that Option.

d. SoCalGas and SDG&E's noncore transportation revenue requirements shall continue to be subject to 100% balancing account treatment.

4. Backbone

a. BTS reservation charges shall use a 2,978 Mdth/d denominator, to be adjusted annually in SoCalGas' Annual Regulatory Account Update filings.

b. All BTS rates shall be subject to BTBA rate adjustments.

c. SoCalGas' volumetric interruptible BTS rate shall equal its reservation charge SFV rate.

d. SDG&E transmission shall continue to be classified as backbone.

e. SoCalGas shall withdraw its proposal for backbone-only rates from this proceeding. If SoCalGas chooses to resubmit a proposal for backbone-only rates prior to the next TCAP, it will do so in its upcoming application relating to Southern System issues (see Section 6 below). If the Southern System application does not propose a backbone-only rate, the application will address why SoCalGas chose not to re-propose it in the application. Nothing in this Settlement is intended to predetermine the potential availability of a backbone-only rate as a result of the upcoming application.

f. SoCalGas' MFV Rate Option shall be maintained for this TCAP period, with the MFV Volumetric rate designed such that 100% load factor MFV rate equals the SFV "100% Reservation" rate for BTS service.

5. Storage

a. SoCalGas shall receive full rate recovery by SoCalGas of its Honor Rancho Expansion Project costs.

b. The 2009 BCAP Phase 1 Settlement Agreement shall be extended through the end of 2015.

6. Southern System

a. Southern System issues shall be considered in a separate CPUC application submitted by SoCalGas.

III
ADDITIONAL TERMS AND CONDITIONS

A. The Public Interest

The Settlement Parties agree jointly by executing and submitting this Settlement that the relief requested herein is just, fair and reasonable, and in the public interest.

B. Non-Precedential Effect

This Settlement is not intended by the Settling Parties to be precedent for any future proceeding. The Settling Parties have assented to the terms of this Settlement only for the purpose of arriving at the settlement embodied in this Settlement. Except as expressly precluded in this Settlement, each of the Settling Parties expressly reserves its right to advocate, in current and future proceedings, positions, principles, assumptions, arguments and methodologies which may be different than those underlying this Settlement, and the Settling Parties expressly declare that, as provided in Rule 12.5 of the Commission's Rules, this Settlement should not be

considered as a precedent for or against them. Likewise, the Settlement explicitly does not establish any precedent on the litigated issues in the case.

C. Partial Settlement

This Settlement is a partial settlement of Phase 2 issues. It is not intended to resolve issues not covered by the Settlement, or to preclude any of the Settling Parties from making any arguments or taking any positions with respect to such issues.

D. Indivisibility

This Settlement embodies compromises of the Settling Parties' positions. No individual term of this Settlement is assented to by any of the Settling Parties, except in consideration of the other Settling Parties' assents to all other terms. Thus, the Settlement is indivisible and each part is interdependent on each and all other parts. Any party may withdraw from this Settlement if the Commission modifies, deletes from, or adds to the disposition of the matters stipulated herein. The Settling Parties agree, however, to negotiate in good faith with regard to any Commission-ordered changes to the Settlement in order to restore the balance of benefits and burdens, and to exercise the right to withdraw only if such negotiations are unsuccessful.

The Settling Parties acknowledge that the positions expressed in the Settlement were reached after consideration of all positions advanced in the prepared testimony of SoCalGas, SDG&E, DRA, TURN, SCE, IP, SCGC, City of Long Beach, Southwest Gas, and the other interested parties, as well as proposals offered during the settlement negotiations. This document sets forth the entire agreement of the Settling Parties on all of those issues, except as specifically described within the Settlement. The terms and conditions of this Settlement may only be modified in writing subscribed by all Settling Parties.

//

Dated this 20th day of March, 2013.

SOUTHERN CALIFORNIA GAS COMPANY and
SAN DIEGO GAS & ELECTRIC COMPANY

By: _____
Michael R. Thorp
Attorney

DIVISION OF RATEPAYER ADVOCATES

By: _____
Joe Como
Acting Director

THE UTILITY REFORM NETWORK

By: _____
Robert Finkelstein
General Counsel

SOUTHERN CALIFORNIA GENERATION
COALITION

By: _____
Norman A. Pedersen
Attorney for Southern California Generation
Coalition

SOUTHWEST GAS CORPORATION

By: _____
Kyle Stephens
Attorney

Dated this 20th day of March, 2013.

SOUTHERN CALIFORNIA GAS COMPANY and
SAN DIEGO GAS & ELECTRIC COMPANY

By: _____
Michael R. Thorp
Attorney

DIVISION OF RATEPAYER ADVOCATES

By: Karen Paull for Joseph Como
Joseph P. Como
Acting Director

THE UTILITY REFORM NETWORK

By: _____
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SOUTHERN CALIFORNIA GENERATION
COALITION

By: _____
Norman A. Pedersen
Attorney for Southern California Generation
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SOUTHWEST GAS CORPORATION

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Kyle Stephens
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Dated this 20th day of March, 2013.

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SAN DIEGO GAS & ELECTRIC COMPANY

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Michael R. Thorp
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Joe Como
Acting Director

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Coalition

SOUTHWEST GAS CORPORATION

By: _____
Kyle Stephens
Attorney

CITY OF LONG BEACH

By:_____
Patrick H. West
City Manager

INDICATED PRODUCERS

By:_____
Nora Sheriff
Counsel

SOUTHERN CALIFORNIA EDISON COMPANY

By:_____
Steven D. Eisenberg
Vice President

CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

By:_____
Ronald Liebert
Attorney

CITY OF LONG BEACH

By:_____
Patrick H. West
City Manager

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CALIFORNIA MANUFACTURERS & TECHNOLOGY ASSOCIATION

By:_____
Ronald Liebert
Attorney

Appendix A

APPENDIX A

SoCalGas/SDG&E Demand Forecast

	SOCALGAS	**3-Year Average 2013-2015**
Core		
	Residential	233,753
	Core C&I	98,410
	Gas AC	82
	Gas Engine	1,677
	NGV	11,722
	Total Core	**345,646**
Noncore		
	Noncore C&I	154,762
	Electric Generation	297,505
	EOR	20,392
	Total Retail Noncore	**472,659**
Wholesale and International		
	Long Beach	9,290
	SDG&E	124,756
	Southwest Gas	6,721
	Vernon	8,791
	Mexicali	6,998
	Total Wholesale and International	**156.555**
Average Year Throughput		**974,859**
	SDG&E	**3-Year Average 2013-2015**
Core		
	Residential	32,187
	Core C&I	17,758
	NGV	1,142
	Total Core	**51,086**
Noncore		
	Noncore C&I	3,874
	Electric Generation	68,088
	Total Retail Noncore	**71,962**
Average Year Throughput		**123,049**

Appendix B

APPENDIX B

SoCalGas/SDG&E Marginal Unit Customer-Related Costs

SOCALGAS	Customer Class	SoCalGas $/customer
	Residential	$128.26
	CC&I	$451.32
	G-AC	$3,146.73
	G-GEN	$1,943.50
	NGV	$2,642.27
	NCCI	$20,411.31
	EG Tier 1	$26,075.17
	EG Tier 2	$73,482.69
	EOR	$25,212.67
	Long Beach	$286,516.96
	SDG&E	$578,111.48
	Southwest Gas	$270,524.59
	Vernon	$116,891.71
	DGN	$41,112.29
SDG&E	**Customer Class**	**SDG&E $/customer**
	Residential	$127.69
	CC&I	$238.49
	NGV	$905.03
	NCCI	$7,247.31
	EG Tier 1	$6,184.76
	EG Tier 2	$8,191.22

Appendix C

APPENDIX C

SoCalGas and SDG&E Illustrative Rates[1]

TABLE 1
Natural Gas Transportation Rates
Southern California Gas Company
2013 TCAP Application
2013 TCAP Settlement Agreement Illustrative Rates

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth A	Average Rate $/therm B	Jan-1-12 Revenues $000's C	Proposed Volumes Mth D	Average Rate $/therm E	Proposed Revenues $000's F	Revenue Change $000's G	Rate Change $/therm H	% Rate change % I
1	CORE									
2	Residential	2,483,989	$0.54427	$1,351,948	2,337,534	$0.59030	$1,379,846	$27,898	$0.04603	8.5%
3	Commercial & Industrial	970,519	$0.29905	$290,234	984,102	$0.26925	$264,974	($25,260)	($0.02980)	-10.0%
4										
5	NGV - Pre SempraWide	117,231	$0.07389	$8,662	117,220	$0.07395	$8,669	$7	$0.00006	0.1%
6	SempraWide Adjustment	117,231	($0.00503)	($590)	117,220	$0.00105	$123	$713	$0.00608	-120.9%
7	NGV - Post SempraWide	117,231	$0.06886	$8,072	117,220	$0.07500	$8,792	$720	$0.00615	8.9%
8										
9	Gas A/C	1,210	$0.06682	$81	825	$0.07322	$60	($21)	$0.00640	9.6%
10	Gas Engine	18,080	$0.08848	$1,600	16,774	$0.09723	$1,631	$31	$0.00874	9.9%
11	Total Core	3,591,030	$0.46002	$1,651,935	3,456,455	$0.47890	$1,655,303	$3,368	$0.01888	4.1%
12										
13	NONCORE COMMERCIAL & INDUSTRIAL									
14	Distribution Level Service	982,465	$0.06810	$66,902	893,164	$0.05968	$53,308	($13,594)	($0.00841)	-12.4%
15	Transmission Level Service (3)	457,697	$0.01783	$8,162	654,456	$0.01374	$8,990	$828	($0.00410)	-23.0%
16	Total Noncore C&I	1,440,163	$0.05212	$75,063	1,547,620	$0.04025	$62,298	($12,766)	($0.01187)	-22.8%
17										
18	NONCORE ELECTRIC GENERATION									
19	Distribution Level Service									
20	Pre Sempra Wide	353,995	$0.02981	$10,551	333,969	$0.03523	$11,765	$1,214	$0.00542	18.2%
21	Sempra Wide Adjustment	353,995	($0.00025)	($90)	333,969	($0.00259)	($866)	($776)	($0.00234)	922.2%
22	Distribution Post Sempra Wide	353,995	$0.02955	$10,461	333,969	$0.03263	$10,899	$437	$0.00308	10.4%
23	Transmission Level Service (3)	2,472,969	$0.01719	$42,507	2,641,080	$0.01309	$34,568	($7,939)	($0.00410)	-23.9%
24	Total Electric Generation	2,826,964	$0.01874	$52,968	2,975,049	$0.01528	$45,466	($7,502)	($0.00345)	-18.4%
25										
26	TOTAL RETAIL NONCORE	4,267,127	$0.03000	$128,031	4,522,669	$0.02383	$107,764	($20,267)	($0.00618)	-20.6%
27										
28	WHOLESALE									
29	Wholesale Long Beach (3)	117,093	$0.01719	$2,013	92,897	$0.01309	$1,216	($797)	($0.00410)	-23.9%
30	Wholesale SWG (3)	81,737	$0.01719	$1,405	67,209	$0.01309	$880	($525)	($0.00410)	-23.9%
31	Wholesale Vernon (3)	116,135	$0.01719	$1,996	87,906	$0.01309	$1,151	($846)	($0.00410)	-23.9%
32	International (3)	53,990	$0.01719	$928	69,979	$0.01309	$916	($12)	($0.00410)	-23.9%
33	Total Wholesale & International	368,955	$0.01719	$6,342	317,990	$0.01309	$4,162	($2,180)	($0.00410)	-23.9%
34	SDGE Wholesale	1,230,285	$0.01027	$12,636	1,247,558	$0.00910	$11,348	($1,287)	($0.00117)	-11.4%
35	Total Wholesale Incl SDGE	1,599,240	$0.01187	$18,977	1,565,548	$0.00991	$15,510	($3,467)	($0.00196)	-16.5%
36										
37	TOTAL NONCORE	5,866,366	$0.02506	$147,008	6,088,217	$0.02025	$123,275	($23,734)	($0.00481)	-19.2%
38										
39	Unbundled Storage (5)			$27,530			$26,476	($1,055)		
40	System Total (w/o BTS)	9,457,396	$0.19313	$1,826,474	9,544,672	$0.18912	$1,805,053	($21,421)	($0.00401)	-2.1%
41	Backbone Trans. Service BTS (4)	3,100	$0.11042	$124,939	2,978	$0.12647	$137,465	$12,526	$0.01605	14.5%
42	**SYSTEM TOTALw/BTS**	**9,457,396**	**$0.20634**	**$1,951,413**	**9,544,672**	**$0.20352**	**$1,942,518**	**($8,895)**	**($0.00282)**	**-1.4%**
43										
44	EOR Revenues	156,187	$0.02359	$3,685	203,920	$0.02356	$4,804	$1,119	($0.00003)	-0.1%
45	Total Throughput w/EOR Mth/yr	9,613,583			9,748,592					

1) SoCalGas and SDG&E Illustrative Rate Tables include balancing account amortizations approved for 2012 in SoCalGas and SDG&E's Annual Regulatory Account Update advice letter filings (SoCalGas AL 4314 and SDG&E AL 2082-G).
2) These rates are for Natural Gas Transportation Service from "Citygate to Meter". The BTS rate is for service from Receipt Point to Citygate.
3) These Transmission Level Service "TLS" amounts represent the average transmission rate, see Table 7 or detail list of TLS rates.
4) BTS charge is proposed as a separate rate. Core will pay through procurement rate, noncore as a separate charge.
5 Unbundles Storage costs are not part of the Core Strorage or Load Balancing functions (those are included in transport rates).

TABLE 2
Residential Transportation Rates
Southern California Gas Company
2013 TCAP Application
2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth	Average Rate $/th	Jan-1-12 Revenue $000's	Proposed Volumes Mth	Average Rate $/th	Proposed Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1	RESIDENTIAL SERVICE- Excludes Rate Adder:									
2	Customer Charge									
3	Single Family	3,676,464	$5.00	$220,588	3,663,383	$5.00	$219,803	($785)	$0.00000	0.0%
4	Multi-Family	1,685,965	$5.00	$101,158	1,674,287	$5.00	$100,457	($701)	$0.00000	0.0%
5	Small Master Meter	92,860	$5.00	$5,572	122,347	$5.00	$7,341	$1,769	$0.00000	0.0%
6	Submeter Credit-$/unit/day	149,095	($0.30805)	($16,764)	147,568	($0.23573)	($12,697)	$4,068	$0.07233	-23.5%
7	Volumetric									
8	Baseline Rate	1,703,882	$0.33904	$577,688	1,583,823	$0.37323	$591,123	$13,436	$0.03418	10.1%
9	Non-Baseline Rate	768,363	$0.59904	$460,282	743,221	$0.63323	$470,627	$10,345	$0.03418	5.7%
10		2,472,246	$0.54546	$1,348,523	2,327,044	$0.59159	$1,376,654	$28,132	$0.04612	8.5%
11	NBL/BL Ratio:									
12	Composite Rate $/th		$0.97414			$1.00405			$0.02991	3.1%
13	Gas Rate $/th		$0.45283			$0.43200			($0.02083)	-4.6%
14	NBL/Composite rate ratio (4) =		1.08			1.06				
15	NBL- BL rate difference $/th		0.26000			0.26000			$0.00000	0.0%
16										
17	Large Master Meter Rate (Excludes Rate Adders for CAT):									
18	Customer Charge	61	$339.80	$249	55	$373.78	$248	($1)	$33.98	10.0%
19	Baseline Rate	9,017	$0.10138	$914	7,802	$0.13880	$1,083	$169	$0.03742	36.9%
20	Non-Baseline Rate	2,726	$0.17913	$488	2,688	$0.23549	$633	$145	$0.05636	31.5%
21		11,743	$0.14063	$1,652	10,490	$0.18725	$1,964	$313	$0.04662	33.1%
22										
23	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
24	CSITMA Adder to Volumetric Rate	1,818,370	$0.00065	$1,191	1,671,915	$0.00066	$1,102	($89)	$0.00000	0.6%
25	**Residential:**									
26	**Customer Charge**		**$5.00**			**$5.00**			**$0.00000**	**0.0%**
27	**Baseline $/therm**		**$0.33970**			**$0.37388**			**$0.03419**	**10.1%**
28	**Non-Baseline $/therm**		**$0.59970**			**$0.63388**			**$0.03419**	**5.7%**
29	Average NonCARE Rate $/therm		$0.54612			$0.59225			$0.04613	8.4%
30	Large Master Meter:									
31	Customer Charge		$339.80			$373.78			$33.98	10.0%
32	BaseLine Rate		$0.10204			$0.13946			$0.03742	36.7%
33	NonBaseLine Rate		$0.17978			$0.23615			$0.05636	31.4%
34	Average NonCARE Rate $/therm		$0.14129			$0.18791			$0.04662	33.0%
35	Core Aggregation Transport (CAT) = NonCARE rates + CAT Adder									
36	CAT Adder to Volumetric Rate	13,319	$0.04382	$584	8,732	$0.01442	$126	($458)	($0.02940)	-67%
37	Residential:									
38	Customer Charge		$5.00			$5.00			$0.00	0.0%
39	BaseLine Rate		$0.38352			$0.38831			$0.00479	1.2%
40	NonBaseLine Rate		$0.64352			$0.64831			$0.00479	0.7%
41	Large Master Meter:									
42	Customer Charge		$339.80			$373.78			$33.98	10.0%
43	BaseLine Rate		$0.14586			$0.15388			$0.00802	5.5%
44	NonBaseLine Rate		$0.22360			$0.25057			$0.02697	12.1%
45	Other Adjustments :									
46	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)			($0.00000)	0.6%
47	**TOTAL RESIDENTIAL**	**2,483,989**	**$0.54427**	**$1,351,948**	**2,337,534**	**$0.59030**	**$1,379,846**	**$27,898**	**$0.04603**	**8.5%**

TABLE 3
Core Nonresidential Transportation Rates
Southern California Gas Company
2013 TCAP Application
2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth A	Average Rate $/th B	Jan-1-12 Revenue $000's C	Proposed Volumes Mth D	Average Rate $/th E	Proposed Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1										
2	CORE COMMERCIAL & INDUSTRIAL									
3	Customer Charge 1	127,666	$15.00	$22,980	147,208	$15.00	$26,497	$3,517	$0.00	0.0%
4	Customer Charge 2	87,620	$15.00	$15,772	60,603	$15.00	$10,909	($4,863)	$0.00	0.0%
5	Volumetric Transportation Rate									
6	Tier 1 = 250th/mo	215,926	$0.49316	$106,487	223,928	$0.45173	$101,155	($5,331)	($0.04143)	-8.4%
7	Tier 2 = next 4167 th/mo	488,341	$0.24824	$121,226	495,650	$0.21831	$108,204	($13,022)	($0.02993)	-12.1%
8	Tier 3 = over 4167 th/mo	266,252	$0.08402	$22,371	264,524	$0.06180	$16,347	($6,024)	($0.02222)	-26.4%
9		970,519	$0.29761	$288,835	984,102	$0.26736	$263,112	($25,722)	($0.03025)	-10.2%
10										
11	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
12	CSITMA Adder to Volumetric Rate	966,797	$0.00065	$633	980,381	$0.00066	$646	$13	$0.00000	0.6%
13	**Tier 1 = 250th/mo**		**$0.49382**			**$0.45239**			**($0.04143)**	**-8.4%**
14	**Tier 2 = next 4167 th/mo**		**$0.24889**			**$0.21897**			**($0.02993)**	**-12.0%**
15	**Tier 3 = over 4167 th/mo**		**$0.08467**			**$0.06246**			**($0.02222)**	**-26.2%**
16			$0.29826			$0.26802			**($0.03024)**	**-10.1%**
17	Core Aggregation Transport (CAT):									
18	CAT Adder to Volumetric Rate	17,488	$0.04382	$766	84,283	$0.01442	$1,216	$449	($0.02940)	-67%
19	Tier 1 = 250th/mo		$0.53764			$0.46681			($0.07083)	-13.2%
20	Tier 2 = next 4167 th/mo		$0.29271			$0.23339			($0.05932)	-20.3%
21	Tier 3 = over 4167 th/mo		$0.12849			$0.07688			($0.05161)	-40.2%
22			$0.34209			$0.28245			($0.05964)	-17.4%
23	Other Adjustments :									
24	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)			($0.00000)	0.6%
25										
26	**TOTAL CORE C&I**	**970,519**	**$0.29905**	**$290,234**	**984,102**	**$0.26925**	**$264,974**	**($25,260)**	**($0.02980)**	**-10.0%**
27										
28	NATURAL GAS VEHICLES (a sempra-wide rate)									
29	Customer Charge, P-1	229	$13.00	$36	229	$13.00	$36	$0	$0.00000	0.0%
30	Customer Charge, P-2A	44	$65.00	$34	83	$65.00	$64	$30	$0.00000	0.0%
31	Uncompressed Rate	117,231	$0.05598	$6,563	117,220	$0.06196	$7,263	$700	$0.00598	10.7%
32	Total Uncompressed NGV	117,231	$0.05658	$6,633	117,220	$0.06282	$7,363	$731	$0.00624	11.0%
33	Compressed Rate Adder	1,484	$0.91797	$1,363	1,287	$1.05000	$1,351	($11)	$0.13203	14.4%
34										
35	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
36	CSITMA Adder to Volumetric Rate	117,186	$0.00065	$77	117,175	$0.00066	$77	$0	$0.00000	0.6%
37	**Uncompressed Rate $/therm**		**$0.05664**			**$0.06262**			**$0.00598**	**10.6%**
38	Other Adjustments :									
39	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)			($0.00000)	0.6%
40										
41	**TOTAL NGV SERVICE**	**117,231**	**$0.06886**	**$8,072**	**117,220**	**$0.07500**	**$8,792**	**$720**	**$0.00615**	**8.9%**
42										
43	RESIDENTIAL NATURAL GAS VEHICLES (optional rate)									
44	Customer Charge	5,455	$10.00	$655	5,460	$10.00	$655	$1	$0.00000	0.0%
45	Uncompressed Rate	3,416	$0.17175	$587	5,346	$0.15042	$804	$218	($0.02133)	-12.4%
46		3,416	$0.36342	$1,241	5,346	$0.27298	$1,459	$218	($0.09044)	-24.9%
47	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
48	CSITMA Adder to Volumetric Rate		$0.00065			$0.00066			$0.00000	0.6%
49	**Uncompressed Rate $/therm**		**$0.17241**			**$0.15108**			($0.02133)	-12.4%
50										
51	Core Aggregation Transport (CAT):									
52	CAT Adder to Volumetric Rate	0	$0.04382	$0	0	$0.01442	$0	$0	($0.02940)	-67.1%
53	Uncompressed Rate		$0.21623			$0.16551		$0	($0.05073)	-23.5%
54	Other Adjustments :									
55	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)				
56										
57	**TOTAL RESIDENTIAL NATURAL G**	**3,416**	**$0.36342**	**$1,241**	**5,346**	**$0.27298**	**$1,459**	**$218**	**($0.09044)**	**-24.9%**

TABLE 4
Core Nonresidential Transportation Rates (continued)
Southern California Gas Company
2013 TCAP Application
2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth A	Average Rate $/th B	Jan-1-12 Revenue $000's C	Proposed Volumes Mth D	Average Rate $/th E	Proposed Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1										
2										
3	NON-RESIDENTIAL GAS A/C									
4	Customer Charge	22	$150.00	$40	12	$150	$22	($18)	$0.00000	0.0%
5	Volumetric Rate	1,210	$0.03345	$40	825	$0.04636	$38	($2)	$0.01292	38.6%
6		1,210	$0.06616	$80	825	$0.07256	$60	($20)	$0.00639	9.7%
7	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
8	CSITMA Adder to Volumetric Rate	1,210	$0.00065	$1	825	$0.00066	$1	($0)	$0.00000	0.6%
9	Volumetric		**$0.03410**			**$0.04702**			$0.01292	37.9%
10	Core Aggregation Transport (CAT):									
11	CAT Adder to Volumetric Rate	0	$0.04382	$0	0	$0.01442	$0	$0	($0.02940)	-67.1%
12	Gas A/C Rate		$0.07792			$0.06145		$0	($0.01647)	-21.1%
13	Other Adjustments :									
14	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)				
15										
16	**TOTAL A/C SERVICE**	**1,210**	**$0.06682**	**$81**	**825**	**$0.07322**	**$60**	**($21)**	**$0.00640**	**9.6%**
17										
18	GAS ENGINES									
19	Customer Charge	1,094	$50.00	$656	708	$50	$425	($232)	$0.00000	0.0%
20	Volumetric	18,080	$0.05152	$932	16,774	$0.07124	$1,195	$264	$0.01972	38.3%
21		18,080	$0.08783	$1,588	16,774	$0.09657	$1,620	$32	$0.00874	10.0%
22	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
23	CSITMA Adder to Volumetric Rate	18,080	$0.00065	$12	16,774	$0.00066	$11	($1)	$0.00000	0.6%
24	Volumetric		**$0.05218**			**$0.07190**				
25	Core Aggregation Transport (CAT):									
26	CAT Adder to Volumetric Rate	0	$0.04382	$0	0	$0.01442	$0	$0	($0.02940)	-67.1%
27	Gas Engine Rate		$0.09600			$0.08633		$0	($0.00967)	-10.1%
28	Other Adjustments :									
29	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)				
30										
31	**TOTAL GAS ENGINES**	**18,080**	**$0.08848**	**$1,600**	**16,774**	**$0.09723**	**$1,631**	**$31**	**$0.00874**	**9.9%**
32										
33	STREET & OUTDOOR LIGHTING (equals average Non-CAT CCI Rate)									
34	Street & Outdoor Lighting Base Rate		$0.29761			$0.26736			($0.03025)	-10.2%
35										

TABLE 5

Noncore Commercial & Industrial Rates

Southern California Gas Company

2013 TCAP Application

2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth	Average Rate $/th	Jan-1-12 Revenue $000's	Proposed Volumes Mth	Average Rate $/th	Proposed Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
1	NonCore Commercial & Industrial Distribution Level									
2	Customer Charge	670	$350.00	$2,816	602	$350.00	$2,530	($286)	$0.00000	0.0%
3										
4	Volumetric Rates									
5	Tier 1 = 250kth/yr	147,174	$0.14649	$21,560	133,045	$0.13846	$18,421	($3,139)	($0.00804)	-5.5%
6	Tier 2 = 250k to 1000k	244,409	$0.08854	$21,640	217,578	$0.08217	$17,878	($3,762)	($0.00637)	-7.2%
7	Tier 3 = 1 to 2 million th/yr	130,163	$0.05078	$6,610	109,379	$0.04616	$5,049	($1,561)	($0.00462)	-9.1%
8	Tier 4 = over 2 million th/yr	460,719	$0.02961	$13,643	433,162	$0.02043	$8,851	($4,793)	($0.00918)	-31.0%
9	Volumetric totals (excl itcs)	982,465	$0.06459	$63,454	893,164	$0.05620	$50,199	($13,255)	($0.00838)	-13.0%
10										
11	**Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)**									
12	**CSITMA Adder to Volumetric Rate**		**$0.00065**	**$632**		**$0.00066**	**$579**	**($53)**	**$0.00000**	**0.6%**
13	**Tier 1 = 250kth/yr**		**$0.14715**			**$0.13911**			**($0.00803)**	**-5.5%**
14	**Tier 2 = 250k to 1000k**		**$0.08920**			**$0.08283**			**($0.00637)**	**-7.1%**
15	**Tier 3 = 1 to 2 million th/yr**		**$0.05144**			**$0.04682**			**($0.00462)**	**-9.0%**
16	**Tier 4 = over 2 million th/yr**		**$0.03027**			**$0.02109**			**($0.00918)**	**-30.3%**
			$0.06524			**$0.05686**			**($0.00838)**	**-12.8%**
17	Other Adjustments :									
18	TSA for CSITMA exempt cust.		($0.00065)			($0.00066)			($0.00000)	
19	NCCI - DISTRIBUTION LEVEL	982,465	$0.06810	$66,902	893,164	$0.05968	$53,308	($13,594)	($0.00841)	-12.4%
20										
21	NCCI-TRANSMISSION LEVEL (2) w/	457,697	$0.01783	$8,162	654,456	$0.01374	$8,990	$828	($0.00410)	-23.0%
22										
23	**TOTAL NONCORE C&I**	**1,440,163**	**$0.05212**	**$75,063**	**1,547,620**	**$0.04025**	**$62,298**	**($12,766)**	**($0.01187)**	**-22.8%**

TABLE 6

Noncore Electric Generation Rates and Enhanced Oil Recovery Rates

Southern California Gas Company

2013 TCAP Application

2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth A	Average Rate $/th B	Jan-1-12 Revenue $000's C	Proposed Volumes Mth D	Average Rate $/th E	Proposed Revenue $000's F	Revenue Change $000's G	Rate Change $/th H	% Rate change % I
1										
2	ELECTRIC GENERATION									
3										
4	EFBA Exempt Distribution Rates:									
5	EG Distribution Level Service Tier 1:									
6	Customer Charge	134	$50.00	$80	147	$50.00	$88	$8	$0.00000	0.0%
7	Volumetric Rate (excl ITCS)	60,420	$0.05470	$3,305	42,850	$0.06826	$2,925	($380)	$0.01356	24.8%
8	EG Distribution Level Service Tier 1	60,420	$0.05603	$3,385	42,850	$0.07032	$3,013	($372)	$0.01429	25.5%
9										
10	EG Distribution Level Service Tier 2:									
11	Customer Charge	32	$0.00	$0	34	$0.00	$0	$0	$0.00000	
12	Volumetric Rate (excl ITCS)	293,575	$0.02410	$7,076	291,119	$0.02709	$7,885	$809	$0.00298	12.4%
13	EG Distribution Level Service Tier 2	293,575	$0.02410	$7,076	291,119	$0.02709	$7,885	$809	$0.00298	12.4%
14										
15	Total EG Distribution EFBA Exempt (	353,995	$0.02955	$10,461	333,969	$0.03263	$10,899	$437	$0.00308	10.4%
16										
17	EFBA Non-Exempt Rates:									
18	EFBA Cost Adder	328,957	$0.00000	$0	235,121	$0.00000	$0	$0	$0.00000	
19	**EG-Distribution Tier 1 w/EFBA Adder**		**$0.05470**			**$0.06826**			**$0.01356**	**24.8%**
20	**EG-Distribution Tier 2 w/EFBA Adder**		**$0.02410**			**$0.02709**			**$0.00298**	**12.4%**
21	Total - EG Distribution Level	353,995	$0.02955	$10,461	333,969	$0.03263	$10,899	$437	$0.00308	10.4%
22										
23	EG Transmission Level (2)	2,472,969	$0	$42,507	2,641,080	$0.01309	$34,568	($7,939)	($0.00410)	-23.9%
24										
25	**TOTAL ELECTRIC GENERATION**	**2,826,964**	**$0.01874**	**$52,968**	**2,975,049**	**$0.01528**	**$45,466**	**($7,502)**	**($0.00345)**	**-18.4%**
26										
27	EOR Rates & revenue:									
28	Distribution Level EOR:									
29	Customer Charge	14	$500.00	$84	23	$500.00	$138	$54	$0.00000	0.0%
30	Volumetric Rate	80,880	$0.02851	$2,306	109,229	$0.03137	$3,427	$1,120	$0.00286	10.0%
31	Distribution Level EOR	80,880	$0.02955	$2,390	109,229	$0.03263	$3,565	$1,174	$0.00308	10.4%
32	Transmission Level EOR	75,307	$0	$1,294	94,691	$0.01309	$1,239	($55)	($0.00410)	-23.9%
33	**Total EOR**	**156,187**	**$0.02359**	**$3,685**	**203,920**	**$0.02356**	**$4,804**	**$1,119**	**($0.00003)**	**-0.1%**

TABLE 7
Transmission Level Service Transportation Rates
Southern California Gas Company
2013 TCAP Application
2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth	Average Rate $/th	Jan-1-12 BCAP Vols $000's	Proposed Volumes Mth, Mdth	Average Rate $/th	Proposed Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
	Rate applicable to NonCore C&I, EOR & EG customer Classes:									
1	Reservation Service Option (RS):									
2	Daily Reservation rate $/th/day		$0.00844			$0.00641			($0.00203)	-24.1%
3	Usage Charge for RS $/th		$0.00481			$0.00444			($0.00036)	-7.6%
4										
5	Class Average Volumetric Rate (CA)									
6	Volumetric Rate $/th		$0.01218			$0.00863			($0.00355)	-29.1%
7	Usage Charge for CA $/th		$0.00500			$0.00444			($0.00055)	-11.1%
8	Class Average Volumetric Rate (CA) $/th		$0.01718			$0.01307			($0.00410)	-23.9%
9										
10	115% CA (for NonBypass Volumetric NV) $/th		$0.02061			$0.01504			($0.00557)	-27.0%
11	135% CA (for Bypass Volumetric BV) $/th		$0.02319			$0.01765			($0.00554)	-23.9%
12	Total Transmission Level Service (N	2,930,667	$0.01719	$50,374	3,295,536	$0.01309	$43,133	($7,240)	($0.00410)	-23.9%
13										
14	Rate applicable to NonCore C&I for CSITMA and EFBA NonExempt Customers									
15	CSITMA Adder to Usage Charge	457,697	$0.00064	$294	654,456	$0.00065	$424	$130	$0.00000	
16	EFBA Cost Adder	1,016,987	$0.00000	$0	1,455,666	$0.00000	$0		$0.00000	
17	**Reservation Service Option (RS):**									
18	**Daily Reservation rate $/th/day**		**$0.00844**			**$0.00641**		**$0**	**($0.00203)**	**-24.1%**
19	**Usage Charge for RS $/th**		**$0.00545**			**$0.00509**		**$0**	**($0.00036)**	**-6.6%**
20										
21	**Class Average Volumetric Rate (CA)**									
22	**Volumetric Rate $/th**		**$0.01218**			**$0.00863**		**$0**	**($0.00355)**	**-29.1%**
23	**Usage Charge for CA $/th**		**$0.00564**			**$0.00509**		**$0**	**($0.00055)**	**-9.7%**
24	**Class Average Volumetric Rate (CA) $/th**		**$0.01782**			**$0.01372**		**$0**	**($0.00410)**	**-23.0%**
25										
26	**115% CA (for NonBypass Volumetric NV) $/t**		**$0.02138**			**$0.01578**		**$0**	**($0.00560)**	**-26.2%**
27	**135% CA (for Bypass Volumetric BV) $/th**		**$0.02405**			**$0.01853**		**$0**	**($0.00553)**	**-23.0%**
28										
29	Other Adjustments :									
30	TSA for CSITMA exempt cust.		($0.00064)			$0.00065			$0.00129	
31	Total Transmission Level Service (N	2,930,667	$0.01729	$50,668	3,295,536	$0.01322	$43,558	($7,111)	($0.00407)	-23.6%
32										
33	**Rate applicable to Wholesale & International customer Classes:**									
34	Reservation Service Option (RS):									
35	Daily Reservation rate $/th/day		$0.00842			$0.00639			($0.00203)	-24.1%
36	Usage Charge for RS $/th		$0.00480			$0.00443			($0.00036)	-7.6%
37										
38	Class Average Volumetric Rate (CA)									
39	Volumetric Rate $/th		$0.01215			$0.00861			($0.00354)	-29.1%
40	Usage Charge for CA $/th		$0.00499			$0.00443			($0.00055)	-11.1%
41	Class Average Volumetric Rate (CA) $/th		$0.01713			$0.01304			($0.00409)	-23.9%
42										
43	115% CA (for NonBypass Volumetric NV) $/th		$0.02056			$0.01500			($0.00556)	-27.0%
44	135% CA (for Bypass Volumetric BV) $/th		$0.02313			$0.01761			($0.00552)	-23.9%
45	Total Transmission Level Service (W	368,955	$0.01719	$6,342	317,990	$0.01309	$4,162	($2,180)	($0.00410)	-23.9%
46										
47	**Average Transmission Level Se**	**3,299,622**	**$0.01728**	**$57,010**	**3,613,526**	**$0.01321**	**$47,720**	**($9,290)**	**($0.00407)**	**-23.6%**

TABLE 8

Backbone Transmission Service and Storage Rates

Southern California Gas Company

2013 TCAP Application

2013TCAP SCG RD Model - All Party Settlement 2/27/2013

		Present Rates			Proposed Rates			Changes		
		Jan-1-12 Volumes Mth	Average Rate $/th	Jan-1-12 BCAP Vols $000's	Proposed Volumes Mth, Mdth	Average Rate $/th	Proposed Revenue $000's	Revenue Change $000's	Rate Change $/th	% Rate change %
		A	B	C	D	E	F	G	H	I
48										
49	**Backbone Transmission Service BTS**									
50	BTS SFV Reservation Charge $/dth	3,100	$0.11042	$124,939	2,978	$0.12647	$137,465	$12,526	$0.01605	14.5%
51	BTS MFV Reservation Charge $/dth/day		$0.08834			$0.10117			$0.01284	14.5%
52	BTS MFV Volumetric Charge $/dth/day		$0.02599			$0.02529			($0.00070)	-2.7%
53	BTS Interruptible Volumetric Charge $/dth		$0.11042			$0.12647			$0.01605	14.5%
54										
55	**Storage Rates: (incl. HRSMA)**									
56	Injection mmcfd; rate = $/dth/day	850	$29.78	$26,074	850	$30.77	$26,770	$697	$1.00	3.3%
57	Inventory BCF; rate = $/dth	135	$0.25768	$35,863	136	$0.25865	$36,030	$167	$0.00098	0.4%
58	Withdrawl mmcfd; rate = $/dth/day	3,195	$9.81	$32,276	3,195	$8.19	$26,770	($5,506)	($1.62)	-16.5%
59				$94,213			$89,571	($4,642)		

TABLE 1
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric
2013 TCAP Application
2013 TCAP Settlement Agreement Illustrative Rates

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms A	Average Rate $/therm B	Jan-1-12 Revenues $000's C	Proposed Volumes mtherms D	Average Rate $/therm E	Proposed Revenues $000's F	Revenues $000's G	Rates $/therm H	Rate change % I
1	**CORE**									
2	Residential	326,003	$0.59205	$193,011	321,869	$0.62118	$199,938	$6,927	$0.02913	4.9%
3	Commerciall & Industrial	158,725	$0.19144	$30,387	177,578	$0.17597	$31,248	$862	($0.01547)	-8.1%
4										
5	NGV - Pre SempraWide	15,238	$0.02704	$412	11,417	$0.09513	$1,086	$674	$0.06809	251.8%
6	SempraWide Adjustment	15,238	$0.03893	$593	11,417	($0.01086)	($124)	($717)	($0.04979)	-127.9%
7	NGV Post SempraWide	15,238	$0.06597	$1,005	11,417	$0.08427	$962	($43)	$0.01831	27.7%
8										
9	Total CORE	499,967	$0.44883	$224,402	510,864	$0.45442	$232,148	$7,746	$0.00559	1.2%
10										
11	**NONCORE COMMERCIAL & INDUSTRIAL**									
12	Distribution Level Service	37,270	$0.12163	$4,533	25,161	$0.12361	$3,110	($1,423)	$0.00199	1.6%
13	Transmission Level Service (2)	3,193	$0.01869	$60	13,582	$0.01456	$198	$138	($0.00413)	-22.1%
14	Total Noncore C&I	40,463	$0.11350	$4,593	38,743	$0.08538	$3,308	($1,285)	($0.02812)	-24.8%
15										
16	**NONCORE ELECTRIC GENERATION**									
17	Distribution Level Service									
18	Pre Sempra Wide	179,522	$0.02857	$5,130	103,761	$0.02560	$2,656	($2,473)	($0.00297)	-10.4%
19	Sempra Wide Adjustment	179,522	$0.00050	$90	103,761	$0.00840	$871	$781	$0.00789	########
20	Distribution Level Post S	179,522	$0.02908	$5,220	103,761	$0.03400	$3,528	($1,692)	$0.00492	16.9%
21	Transmission Level Service (2)	496,393	$0.01719	$8,532	577,118	$0.01309	$7,554	($979)	($0.00410)	-23.9%
22	Total Electric Generation	675,916	$0.02035	$13,752	680,879	$0.01627	$11,081	($2,671)	($0.00407)	-20.0%
23										
24	**TOTAL NONCORE**	716,379	$0.02561	$18,345	719,622	$0.02000	$14,389	($3,956)	($0.00561)	-21.9%
25										
26	**SYSTEM TOTAL**	**1,216,345**	**$0.19957**	**$242,747**	**1,230,486**	**$0.20036**	**$246,538**	**$3,790**	**$0.00079**	**0.4%**

1) These rates are for Natural Gas Transportation Service from "Citygate to Meter".
2) The BTS rate is for service from Receipt Point to Citygate and is purchased from SoCalGas. See SoCalGas' Table 8 for actual BTS rates.
3) These Transmission Level Service "TLS" amounts represents the average transmission rate. See Table 6 for detail list of TLS rates.

TABLE 2
Core Gas Transportation Rates
San Diego Gas & Electric
2013 TCAP Application
2013TCAP SDGE RD Model - All Party Settlement 2/27/2013

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms	Average Rate $/therm	Jan-1-12 Revenues $000's	Proposed Volumes mtherms	Average Rate $/therm	Proposed Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**RESIDENTIAL RATES Schedule GR,GM**									
2	Basis for Rates (Excludes Rate Adders for CSITMA & CAT)									
3	Customer Charge $/month	0	$0.00	$0	848,086	$0.00	$0	$0	$0.00	
4										
5	Baseline $/therm	220,010	$0.55450	$121,995	217,220	$0.58419	$126,898	$4,903	$0.02969	5.4%
6	Non-Baseline $/therm	105,993	$0.69934	$74,125	104,649	$0.73030	$76,425	$2,301	$0.03097	4.4%
7	Average Rate $/therm	326,003	$0.60159	$196,120	321,869	$0.63170	$203,323	$7,204	$0.03011	5.0%
8	NBL/BL Ratio									
9	Composite Rate $/th					$0.99623				
10	NBL/Composite rate ratio		1.14			1.16				
11	NBL- BL rate difference $/th					0.14611				
12										
13	Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)									
14	CSITMA Adder to Volumetric Rate	260,710	$0.00150	$390	256,575	$0.00147	$377	($14)	($0.00003)	-1.9%
15	Baseline $/therm		$0.55599			$0.58566			$0.02966	5.3%
16	Non-Baseline $/therm		$0.70083			$0.73177			$0.03094	4.4%
17	Average NonCARE Rate $/therm		$0.60309			$0.63316			$0.03008	5.0%
18										
19	**Sub Meter Credit Schedule GS,GT**									
20	GS Unit Discount $/day	6,004	($0.25493)	($559)	6,004	($0.29392)	($644)	($85)	($0.03899)	15.3%
21	GT Unit Discount $/day	27,745	($0.34064)	($3,450)	27,745	($0.36460)	($3,692)	($243)	($0.02396)	7.0%
22										
23	**Schedule GL-1**									
24	LNG Facility Charge, domestic us	321	$14.79	$57	289	$14.79	$51		$0.00000	0.0%
25	LNG Facility Charge, non-domestic use $/mth/		$0.05480			$0.05480			$0.00000	0.0%
26	LNG Volumetric Surcharge $/th	110	$0.16571	$18	100	$0.16571	$16		$0.00000	0.0%
27				$75			$68			
28	**Core Aggregation CAT Schedule GTC & GTCA (transprt only NonCARE rate + CAT Adder)**									
29	CAT Adder to Volumetric Rate	247	$0.00000	$0	247	$0.00000	$0	$0	$0.00000	
30	Baseline $/therm		$0.55599			$0.58566			$0.02966	5.3%
31	Non-Baseline $/therm		$0.70083			$0.73177			$0.03094	4.4%
32	Average Rate $/therm		$0.60309			$0.63316			$0.03008	5.0%
33										
34	**Other Adjustments :**									
35	Employee Discount			($459)			($412)	$47		
36	SDFFD			$893			$919	$26		
37	Credit for CSITMA Exempt Cutomers:									
38	NonCARE $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
39										
40										
41	**Total Residential**	**326,003**	**$0.59205**	**$193,011**	**321,869**	**$0.62118**	**$199,938**	**$6,927**	**$0.02913**	**4.9%**

TABLE 3
Natural Gas Transportation Rate Revenues
San Diego Gas & Electric
2013 TCAP Application
2013TCAP SDGE RD Model - All Party Settlement 2/27/2013

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms	Average Rate $/therm	Jan-1-12 Revenues $000's	Proposed Volumes mtherms	Average Rate $/therm	Proposed Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**Other Core Rates $/therm**									
2	Schedule GPC - Procurement Price		$0.45283			$0.43200			($0.02083)	-4.6%
3										
4	**CORE COMMERCIAL & INDUSTRIAL RATES Schedule GN-3**									
5	Customer Charge $/month	29,831	$10.00	$3,580	29,865	$10.00	$3,584	$4	$0.00000	0.0%
6										
7	Basis for Volumetric Rates (Excludes Rate Adders for CSITMA & CAT)									
8	Tier 1 = 0 to 1,000 therms/month	69,961	$0.24322	$17,016	79,475	$0.22648	$18,000	$984	($0.01674)	-6.9%
9	Tier 2 = 1,001 to 21,000 therms/m	74,938	$0.11165	$8,367	82,322	$0.09996	$8,229	($138)	($0.01169)	-10.5%
10	Tier 3 = over 21,000 therms/mon	13,826	$0.07448	$1,030	15,781	$0.06421	$1,013	($16)	($0.01027)	-13.8%
11										
12	Volumetric Rates for CSITMA Non-Exempt, NonCARE Customers (Rate Basis + CSITMA Adder)									
13	CSITMA Adder to Volumetric Rate	150,500	$0.00150	$225	169,353	$0.00147	$249	$23	($0.00003)	-1.9%
14	Tier 1 = 0 to 1,000 therms/month		$0.24472			$0.22795			($0.01677)	-6.9%
15	Tier 2 = 1,001 to 21,000 therms/month		$0.11314			$0.10142			($0.01172)	-10.4%
16	Tier 3 = over 21,000 therms/month		$0.07598			$0.06568			($0.01029)	-13.5%
17										
18	**Core Aggregation CAT Schedule GTC & GTCA (transprt only volumetric rate + CAT adder)**									
19	CAT Adder to Volumetric Rate	23,606	$0.00000	$0	23,606	$0.00000	$0	$0	$0.00000	
20	Tier 1 = 0 to 1,000 therms/month		$0.24472			$0.22795			($0.01677)	-6.9%
21	Tier 2 = 1,001 to 21,000 therms/month		$0.11314			$0.10142			($0.01172)	-10.4%
22	Tier 3 = over 21,000 therms/month		$0.07598			$0.06568			($0.01029)	-13.5%
23										
24	**Other Adjustments :**									
25	Adjustment for SDFFD			$169			$174	$5		
26	Credit for CSITMA Exempt Cutomers:									
27	NonCARE $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
28										
29										
30	**Total Core C&I**	**158,725**	**$0.19144**	**$30,387**	**177,578**	**$0.17597**	**$31,248**	**$862**	**($0.01547)**	**-8.1%**

TABLE 4
Other Core Gas Transportation Rates
San Diego Gas & Electric
2013 TCAP Application
2013TCAP SDGE RD Model - All Party Settlement 2/27/2013

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms	Average Rate $/therm	Jan-1-12 Revenues $000's	Proposed Volumes mtherms	Average Rate $/therm	Proposed Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**NATURAL GAS VEHICLE RATES**	Sempra-Wide NGV Rates			*Sempra-Wide NGV Rates*					
2	Customer Charge									
3	P1 $/month	30	$13.00	$5	24	$13.00	$4	($1)	$0.00	0.0%
4	P2A $/month	10	$65.00	$8	10	$65.00	$8	$0	$0.00	0.0%
5										
6	Uncompressed Rate (excludes Ra	15,238	$0.05630	$858	11,417	$0.06232	$711	($146)	$0.00602	10.7%
7	Compressor Adder $/therm	119	$0.92324	$110	209	$1.05603	$220	$110	$0.13279	14.4%
8										
9	Volumetric Rates for CSITMA Non-Exempt Customers (Rate Basis + CSITMA Adder)									
10	CSITMA Adder to Volumetric Rate	15,221	$0.00150	$23	11,399	$0.00147	$17	($6)	($0.00003)	-1.9%
11	Uncompressed Rate $/therm		$0.05780			$0.06379		$0	$0.00599	10.4%
12										
13	Volumetric Rates for CSITMA Non-Exempt CAT Customers (Rate Basis + CSITMA Adder)									
14	CAT Adder to Volumetric Rate		$0.00000			$0.00000				
15	Uncompressed Rate $/therm		$0.05780			$0.06379		$0	$0.00599	10.4%
16										
17	**Other Adjustments :**									
18	Adjustment for SDFFD			$2			$2	$0		
19	Credit for CSITMA Exempt Cutomers $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
20										
21	**Total NGV**	**15,238**	**$0.06597**	**$1,005**	**11,417**	**$0.08427**	**$962**	**($43)**	**$0.01831**	**27.7%**
22										
23	**RESIDENTIAL NATURAL GAS VEHICLES (optional rate)**									
24	Customer Charge	832	$5.00	$50	848	$5.00	$51	$1	$0.00	0.0%
25	Uncompressed Rate (excludes Ra	521	$0.23110	$120	929	$0.19942	$185	$65	($0.03167)	-13.7%
26		521	$0.32693	$170	929	$0.25418	$236	$66	($0.07274)	-22.3%
27										
28	Volumetric Rates for CSITMA Non-Exempt Customers (Rate Basis + CSITMA Adder)									
29	CSITMA Adder to Volumetric Rate		$0.00150			$0.00147			($0.00003)	-1.9%
30	Uncompressed Rate $/therm		$0.23260			$0.20089			($0.03171)	-13.6%
31										
32	Core Aggregation Transport (CAT):									
33	CAT Adder to Volumetric Rate	0	$0.00000	$0	0	$0.00000	$0	$0	$0.00000	
34	Uncompressed Rate $/therm		$0.23260			$0.20089		$0	($0.03171)	-13.6%
35										
36	**Other Adjustments :**									
37	Adjustment for SDFFD	0		$0			$0	$0		
38	Credit for CSITMA Exempt Cutomers $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
39										
40										
41	**Total Res NGV**	**521**	**$0.32693**	**$170**	**929**	**$0.25418**	**$236**	**$66**	**($0.07274)**	**-22.3%**

TABLE 5
NonCore Gas Transportation Rates
San Diego Gas & Electric
2013 TCAP Application
2013TCAP SDGE RD Model - All Party Settlement 2/27/2013

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms	Average Rate $/therm	Jan-1-12 Revenues $000's	Proposed Volumes mtherms	Average Rate $/therm	Proposed Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**NonCore Commercial & Industrial Distribution Level**									
2	Customer Charges $/month	60	$350.00	$252	54	$350.00	$228	($24)	$0.00	0.0%
3										
4	Volumetric Charges$/therm	37,270	$0.11350	$4,230	25,161	$0.11328	$2,850	($1,380)	($0.00022)	-0.2%
5	CSITMA Adder to Volumetric Rate	33,927	$0.00150	$51	21,818	$0.00147	$32	($19)	($0.00003)	-1.9%
6	Volumetric Rates for CSITMA Non-Exempt Cust		$0.11500			$0.11475			($0.00025)	-0.2%
7										
8	**Other Adjustments :**									
9	SDFFD									
10	Credit for CSITMA Exempt Cutomers $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
11										
12	**NCCI-Distribution Total**	**37,270**	**$0.12163**	**$4,533**	**25,161**	**$0.12361**	**$3,110**	**($1,423)**	**$0.00199**	**1.6%**
13										
14	**NCCI-Transmission Total (1)**	**3,193**	**$0.01869**	**$60**	**13,582**	**$0.01456**	$198	**$138**	**($0.00413)**	**-22.1%**
15										
16	**Total NonCore C&I**	**40,463**	**$0.11350**	**$4,593**	**38,743**	**$0.08538**	**$3,308**	**($1,285)**	**($0.02812)**	**-24.8%**
17										
18	**ELECTRIC GENERATION**									
19										
20	**EFBA Exempt Distribution Rates:**									
21	Small EG Ditsribution Level Service:									
22	Customer Charge, $/month	57	$50.00	$34	40	$50.00	$24	($10)	$0.00	0.0%
23	Volumetric Rate (Incl ITCS) $/ther	27,097	$0.05501	$1,491	16,347	$0.06865	$1,122	($368)	$0.01	24.8%
24										
25	Large EG Ditsribution Level Service:									
26	Customer Charge, $/month									
27	Volumetric Rate (Incl ITCS) $/ther	152,425	$0.02424	$3,695	87,414	$0.02724	$2,381	($1,314)	$0.00	12.4%
28										
29	EG Distribution EFBA Exempt Cust	179,522	$0.02908	$5,220	103,761	$0.03400	$3,528	($1,692)	$0.00	16.9%
30										
31	**EFBA Non-Exempt Rates:**									
32	EFBA Cost Adder	172,384	$0.00000	$0	96,623	$0.00000	$0	$0	$0.00000	
33	EG-Distribution Tier 1 w/EFBA Adder		$0.05501			$0.06865			$0.01364	24.8%
34	EG-Distribution Tier 2 w/EFBA Adder		$0.02424			$0.02724			$0.00300	12.4%
35	**Total - EG Distribution Level**	**179,522**	**$0.02908**	**$5,220**	**103,761**	**$0.03400**	**$3,528**	**($1,692)**	**$0.00492**	**16.9%**
36										
37	EG Transmission Level Service (1	496,393	$0.02	$8,532	577,118	$0.01309	**$7,554**	($979)	($0.00)	-23.9%
38										
39	**TOTAL ELECTRIC GENERATION**	**675,916**	**$0.02035**	**$13,752**	**680,879**	**$0.01627**	**$11,081**	**($2,671)**	**($0.00407)**	**-20.0%**

TABLE 6

Transmission Level Service Gas Transportation Rates

San Diego Gas & Electric

2013 TCAP Application

2013TCAP SDGE RD Model - All Party Settlement 2/27/2013

		At Present Rates			At Proposed Rates			Changes		
		Jan-1-12 Volumes mtherms	Average Rate $/therm	Jan-1-12 Revenues $000's	Proposed Volumes mtherms	Average Rate $/therm	Proposed Revenues $000's	Revenues $000's	Rates $/therm	Rate change %
		A	B	C	D	E	F	G	H	I
1	**Transmission Level Service Rate (excludes CSITMA adder, for EFBA exempt customers):**									
2	Reservation Service Option (RS):									
3	Daily Reservation rate $/th/day		$0.00849			$0.00645		$0	($0.00204)	-24.1%
4	Usage Charge for RS $/th		$0.00484			$0.00447		$0	($0.00037)	-7.6%
5										
6	Class Average Volumetric Rate (CA)									
7	Volumetric Rate $/th		$0.01225			$0.00868		$0	($0.00357)	-29.1%
8	Usage Charge for CA $/th		$0.00503			$0.00447		$0	($0.00056)	-11.1%
9	Class Average Volumetric Rate CA $/th		$0.01727			$0.01315		$0	($0.00412)	-23.9%
10										
11	115% CA (for NonBypass Volumetric NV) $/th		$0.02073			$0.01512		$0	($0.00561)	-27.0%
12	135% CA (for Bypass Volumetric BV) $/th		$0.02332			$0.01775		$0	($0.00557)	-23.9%
13										
14	Average Transmission Level Serv	499,587	$0.01719	$8,587	590,700	$0.01309	$7,731	($856)	($0.00410)	-23.9%
15										
16	**Transmission Level Service Rate for CSITMA NonExempt Customers and for EFBA NonExempt Customers:**									
17	Credit for CSITMA Exempt Cutom	$3,193	$0.00150	$5	13,582	$0.00147	$20	$15	($0.00003)	-1.9%
18	EFBA Cost Adders for Non-Exem	28502.954	$0.00000	$0	119,616	$0.00000	$0		$0.00000	
19	Reservation Service Option (RS):									
20	Daily Reservation rate $/th/day		$0.00849			$0.00645		$0	($0.00204)	-24.1%
21	Usage Charge for RS $/th		$0.00633			$0.00594		$0	($0.00040)	-6.2%
22										
23	Class Average Volumetric Rate (CA)									
24	Volumetric Rate $/th		$0.01225			$0.00868		$0	($0.00357)	-29.1%
25	Usage Charge for CA $/th		$0.00652			$0.00594		$0	($0.00059)	-9.0%
26	Class Average Volumetric Rate CA $/th		$0.01877			$0.01462		$0	($0.00415)	-22.1%
27										
28	115% CA (for NonBypass Volumetric NV) $/th		$0.02253			$0.01681		$0	($0.00571)	-25.4%
29	135% CA (for Bypass Volumetric BV) $/th		$0.02534			$0.01973		$0	($0.00561)	-22.1%
30										
31	**Other Adjustments:**									
32	Credit for CSITMA Exempt Cutomers $/th		($0.00150)			($0.00147)			$0.00003	-1.9%
33										
34	**Average Transmission Level**	**499,587**	**$0.01720**	**$8,592**	**590,700**	**$0.01312**	**$7,751**	**($841)**	**($0.00408)**	**-23.7%**

(End of Attachment III)